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# Unlocking load growth at the grid edge: Practices for managing, recovering, and allocating distribution system investments

Guillermo Pereira, Jeff Deason, and Anthony Sandonato

January 2025

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# Unlocking load growth at the grid edge: Practices for managing, recovering, and allocating distribution system investments

Prepared for the
Office of Deployment and Infrastructure Policy
U.S. Department of Energy

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# Acronyms and Abbreviations

| | |
|---|---|
| AB | Assembly Bill |
| C&I | Commercial and industrial |
| CAISO | California Independent System Operator |
| CREZ | Competitive Renewable Energy Zones |
| DCFC | Direct current fast charging |
| DER | Distributed energy resources |
| EJ | Environmental justice |
| ESMP | Electric Sector Grid Modernization Plans |
| EV | Electric vehicle |
| FERC | Federal Energy Regulatory Commission |
| GMAC | Grid Modernization Advisory Council |
| GW | Gigawatt |
| ISO-NE | Independent System Operator New England |
| KVA | Kilovolt-ampere |
| kWh | Kilowatt-hour |
| MHDEV | Medium and Heavy-Duty Electric Vehicle |
| MISO | Midcontinent Independent System Operator |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NERC | North American Electric Reliability Corporation |
| NRDC | Natural Resource Defense Council |
| NWA | Non-Wires Alternative |
| NYISO | New York Independent System Operator |
| PG&E | Pacific Gas & Electric Company |
| PJM | PJM Interconnection |
| RE | Renewable energy |
| SB | Senate Bill |
| SCE | Southern California Edison |
| SDG&E | San Diego Gas & Electric |
| TOU | Time-of-use |

# Executive Summary

Driven by expectations of increased electricity load growth in coming years and decades, utilities and utility regulators are preparing to make significant investments in the electricity distribution system. Regulators will be tasked with vetting investment proposals and implementing cost recovery and allocation mechanisms. State regulators are anticipating the need to make proactive distribution system investments, building the capability to serve new load in advance of demand.

In this report, we focus on load growth from homes and businesses that adopt electric vehicles and heat pump heating technologies. Through review of legislation and regulatory dockets in a subset of states, we provide insights into emerging utility and regulatory practices to recover and allocate costs of electrification-driven distribution system investments necessary to accommodate these technologies. Our report is largely descriptive, offering detailed information about approaches different state commissions and utilities have implemented to inform future decision-making. We focus on regulated investor-owned utilities, though some of our findings may prove relevant to publicly-owned utilities.

We separate our review into three topics:

- **Programs**: Practices for managing, recovering, and allocating costs related to enabling infrastructure investments made through utility-funded programs
- **Line extension policies**: Practices for dividing financial responsibility for close to the meter utility-side investments, such as electricity service upgrades, between utilities and adopting customers through line extension policies
- **Proactive investments**: Practices for making and recovering the costs of larger investments further upstream in the distribution system in advance of load to accommodate uncertain future demand

## *Programs*

Utility programs support customer adoption of electric vehicles and heat pump technologies, which are not the focus of this report. However, many of these programs also support some electricity delivery infrastructure. Depending on program design, this may include utility-side infrastructure, such as service lines and transformers, and customer-side infrastructure, such as wiring, conduits, electric vehicle chargers, or electrical panel upgrades. Regulators review utility proposals to recover the costs of these programs from their customers. Program cost recovery and allocation decisions regulators face include:

- Whether to capitalize or expense electrification program costs. Capitalization provides a rate of return, creating a utility incentive for investment, and typically spreads costs over a longer time period (e.g., the expected lifetime of the asset being capitalized), reducing up-front rate impacts. Expensing lowers the total increase in the rate base because the utility does not earn a rate of return, but increases short-term impacts on ratepayers, as expensing often happens on a shorter timeframe equal to the program's duration (e.g., 3-4 years).

- The time frame over which costs are capitalized, if applicable. In many cases, this time period will coincide with the expected useful life of the asset; however, there may be reasons to choose other periods based on policy goals or desired timing of rate impacts.
- Whether to recover program costs through base rates, or to establish a rider (or other alternative cost recovery mechanism). Relative to base rates, riders generally offer faster cost recovery and greater flexibility. Handling cost recovery through rate cases may offer greater cost certainty and may accommodate greater regulatory oversight of costs.
- Whether to use an existing cost allocation method, such as those established in the most recent rate case, or to establish a new method for electrification program costs. Existing methods have the advantage of prior regulatory vetting, while new methods may offer the opportunity to better match the costs of these investments with their beneficiaries.
- Whether to introduce specific guidance regarding the reasonableness of proposed utility electrification-related investments. Such guidance can provide greater clarity for utilities developing investment strategies and submitting program or investment proposals.

### *Line extensions*

In some cases, customers adding new electric loads may need an electric service upgrade, which may delay the ability to serve new loads and increase costs. Line extension policies divide cost responsibilities between the utility and customers for utility side infrastructure needed to serve new loads. Customers generally receive a capped allowance to cover line extension costs. Traditionally, these policies did not include electrification-specific considerations. However, a number of utilities have recently modified line extension policies to provide more financial support for electrifying customers. Approaches that utilities have taken, and that other utilities and their regulators may wish to consider, include:

- Increasing the line extension allowance for customers adopting electric vehicles or heat pumps, or waiving customer contributions altogether
- Exempting certain equipment, such as transformer upgrades, from customer line extension charges, especially when this equipment is likely to provide value to other customers in the future
- Making line extension costs refundable should the deployed infrastructure subsequently support load increases from other customers

Many state line extension policy revisions are driven by legislative, executive, or regulatory action in pursuit of related policy goals. Regardless of motivation, utilities may wish to consider the extent to which increased revenue from electricity sales due to customer's adoption of electric technologies may more than offset the costs of an expanded allowance, lowering utility rates for all customers. Utilities may also wish to consider the extent to which system expansions motivated by one customer increase grid capacity to deliver services to other customers when setting line extension policy for customer electrification.

### *Proactive investments in upstream distribution system infrastructure*

Utilities and public utility commissions have traditionally followed a "just-in-time" distribution system investment strategy focused on addressing near-term grid needs, where sufficient visibility exists to ensure that investments result in assets that are utilized and that costs are reasonable. Forecasts of rapid load growth are now motivating regulators and utilities to develop proactive investment frameworks to ensure the distribution system can keep pace with growing demand. We review emerging state frameworks in detail.

Some of the more common features of these emerging proactive investment frameworks that other states may wish to consider include:

- Processes for utilities to identify investments in advance of load for commission approval
- Criteria for evaluation and approval of proposed investments, or processes to establish such criteria
- Requirements for utilities to gather and share relevant data, such as vehicle location and trip data and hosting capacity data
- Target timelines for energization of EV charging infrastructure
- Cost recovery and cost allocation processes for proactive investment costs, including whether to recover proactive investments through base rates or through alternative ratemaking mechanisms
- Criteria for determining the reasonableness of incurred utility costs for cost recovery purposes

Given the inherent uncertainty in investing ahead of load, managing risk - to utility ratepayers, utility shareholders, and customers adopting technologies - is a central task for regulators to grapple with when facilitating proactive investment. Proactive investments must manage stranded asset risks; risks of making suboptimal investments given uncertainty about future load growth; and risks that cost allocation decisions made at the time of investment will not match the eventual beneficiaries of the future investment. Traditional just-in-time investments also involve risks. Waiting for load certainty may create long energization timelines, hampering customer adoption of preferred technologies and threatening policy goals that depend on that adoption. Insufficient distribution system capacity may lock in long-lived incumbent technologies. Utilities will not receive new revenues as quickly, and investments made under time pressure to serve immediate demand may not adequately consider future grid needs.

To manage these risks, regulators can consider:

- Establishing processes that ensure adequate data availability and analysis
- Requiring load forecasting methods that extend time horizons and explicitly consider the uncertainties surrounding the timing of electrification technology adoption
- Requiring third party review of forecasts, analyses, and proposed investments to promote transparency and increase confidence that decisions are made objectively

- Requiring consideration of non-wires alternatives and bridge-to-wires solutions as a strategy for maintaining options in uncertain investment scenarios

Regulators can also consider financial incentives for utilities to make appropriate proactive investments. Approaches could include:

- Incentives that reward utilities for right-sizing distribution systems
- Rate of return or asset depreciation structures that make utility earnings dependent on deployed assets being utilized
- Varying the allowable rate of return depending on the level of risk of the investment
- Setting caps on utility earnings for proactive investment to manage impacts on rates
- Sharing risk with customers (such as through dedicated tariffs) or allowing more risk-tolerant third parties to take on risks of proactive investment

### *Developing a coordinated approach to recovery of electrification-driven distribution system costs*

Regulators may benefit from considering potential complementarities and opportunities for coordination across these mechanisms. For instance, utility electrification programs may be an effective way to pilot line extension policy changes to gather insights and inform longer-term actions. Regulators can also consider coordinating with existing planning efforts, such as integrated distribution system planning, to ensure proactive investment needs are considered alongside other distribution system needs and prioritized accordingly. In some cases, regulators may face similar decisions in separate domains of electrification-related cost recovery. For example, both programmatic and proactive investments must be assessed for reasonableness, allocated among customer segments, and recovered from the rate base. Regulators can consider harmonizing their processes and requirements for these expenses to the extent that it makes sense to do so.

# 1. Introduction

Electricity load is expected to grow rapidly in the near future. Data from the North American Electric Reliability Corporation (NERC) project a 15% increase in summer peak demand (132 GW) and a 18% increase in winter peak demand (149 GW), across the U.S. and Canada, over the next ten years. This load growth will be driven by manufacturing growth, an expansion of data centers and artificial intelligence, cryptocurrency mining, demographic changes, and increasing adoption of beneficial electrification technologies at the grid edge, such as electric vehicles (EV) and heat pumps (EPRI, 2018; NERC, 2024; Trieu et al., 2018; U.S. Energy Information Administration, 2023). Electrification is a near-term load growth driver across several regions, including CAISO, ISO-NE, MISO, NYISO, and PJM, with more regions expecting significant load growth due to electrification after 2030 (see Figure 1-1) (Wilson et al., 2024). The scale of expected load growth contrasts with slow or no load growth over the past two decades in most parts of the country (NERC, 2024). Additionally, the speed at which load is expected to grow is also increasing. For instance, an analysis from Grid Strategies using data from the Federal Energy Regulatory Commission (FERC) and additional preliminary updates showed that over the past two years the five-year nationwide electricity demand forecast increased almost five-fold from 2.8% (23 GW) in 2022 to 15.8% (128 GW) in 2024 (Wilson et al., 2024).

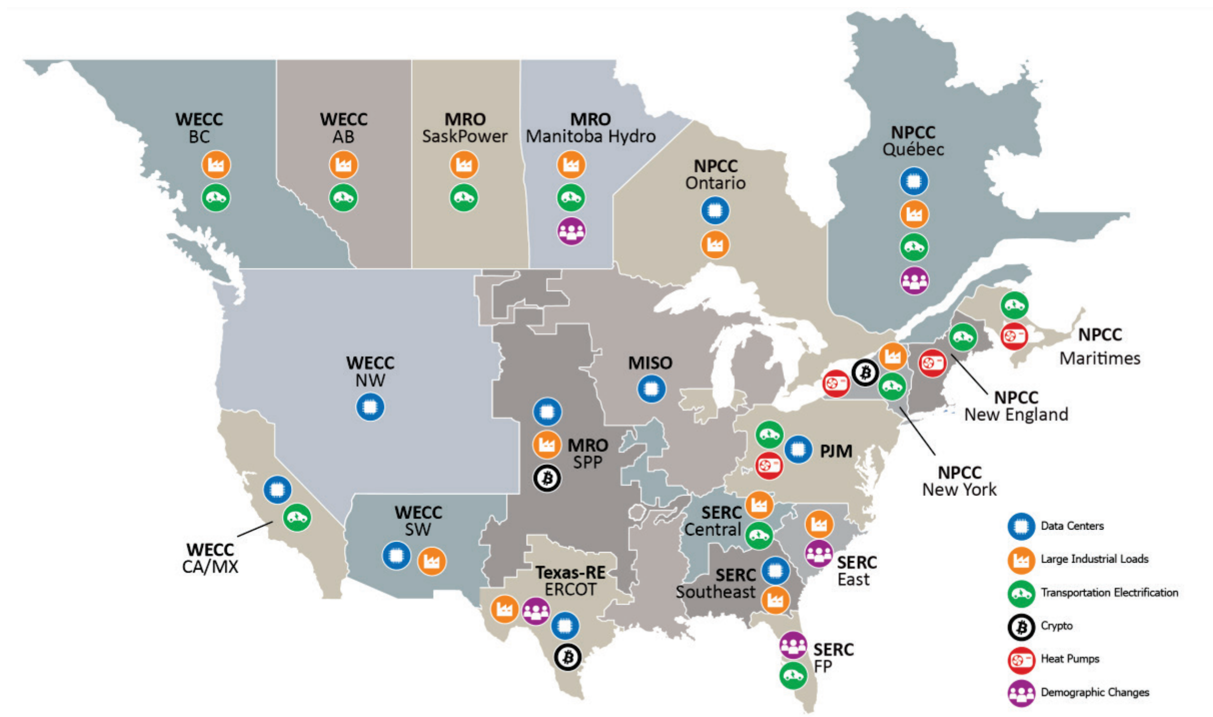


**Figure 1-1. Electricity demand drivers by NERC region**

Source: From NERC (2024: p. 31)

Increased electricity sales resulting from electrification load growth will create downward pressure on rates, and rates may go down if the added sales are sufficient to absorb increased electricity delivery costs. For New York, a recent study found that a program providing distribution system upgrades to enable MHDEVs would result in a neutral-to-beneficial impact on rates for 2023-2045 (Metz et al., 2023). In California, a study for the Public Advocates Office found that electrification would apply downward pressure across the state's three large investor-owned utilities and indicated that all ratepayers would benefit from electrification, including customers who chose not to or are unable to electrify (Public Advocates Office, 2023). A Berkeley Lab study found that managing EV charging and shifting it to off-peak hours could reduce average retail rates by ~0.8%-1% due to reduced distribution system and generation costs (Satchwell et al., 2023). A study analyzing historical data from 2011 to 2021 found that EV charging contributed $3.14 billion of net revenues to utilities, resulting in downward pressure on rates for all ratepayers (Shenstone-Harris et al., 2024).

The distribution system plays a key role in enabling load growth at the grid edge (Blonsky et al., 2019). Amid ongoing electrification, electricity distribution systems are experiencing increasing pressure to ensure sufficient capacity is available to serve new loads by deploying grid upgrades and non-wires alternatives (NWA). This is expected to drive the need for significant investments across the distribution system for a sector that already represents the largest share of capital investments across the power system. As of September 2024, distribution-related capital investments represent 32% (~$60 billion) of total annual capital expenditures (EEI, 2024). Utilities have already made significant investments in programs to prepare the distribution system and enable customers to adopt EV and heat pump technologies. For example, by December 2024, utilities had $6.6 billion approved for investments in transportation electrification (Atlas Public Policy, 2025).

Future estimates illustrate the scale of distribution system investments needed to meet electrification demand growth. A study focused on California identified the need for ~$50 billion in cumulative distribution system upgrades by 2035 to meet the state's transportation and building electrification goals. Notably, $15 billion of the estimated costs are for secondary transformer and electric service upgrades (Kevala, 2023). Following this study, a California Public Advocates Office analysis identified the need for ~$26 billion in feeder and substation upgrade needs by 2025. The lower cost estimate is driven by different assumptions, including lower peak load growth (Public Advocates Office, 2023). For New York, a study focused on transportation electrification found the need for ~$1.4-26.8 billion in cumulative upgrades by 2050. The lower figure is derived from a low distribution system impact scenario, including managed charging and flexible building electrification loads, and the higher figure from a high distribution system impact scenario, including unmanaged charging and building electrification loads with no flexibility (NYSERDA, 2022).[1] For California, Illinois, New York, Oklahoma, and Pennsylvania, a U.S. Department of Energy study found the need for ~$12 billion in incremental infrastructure capital investments by 2032 – of which $9.7 billion are for EV charging infrastructure and $1.6-2.3 billion for distribution grid investments, to meet transportation electrification grid needs under proposed U.S. Environmental Protection Agency rules relative to a baseline electrification scenario (Wood et al., 2024). Behind-the-meter infrastructure costs may also be significant. For example, a study found that up to 48 million households may need a panel upgrade to electrify fully, indicating it could cost up to $100 billion, assuming a $2,000 cost per panel upgrade (Pecan Street, 2021). While existing

[1] Additional details on study scenario assumptions can found in NYSERDA's report at 17-20

studies vary in their scenarios, scope, and regional focus, they emphasize the potential scale of distribution system investments necessary and the importance of understanding how these costs are managed, allocated, and recovered (Chandramowli et al., 2024).

This report provides insights into existing practices for cost recovery and allocation of electrification-driven distribution system investments. We cover the following components of the distribution system (Figure 1-2):

- **Behind-the-meter enabling infrastructure** provided through **utility electrification programs** (Section 2)
- **Close to the meter utility-side investments** deployed through **line extension policies** (Section 3)
- **Upstream distribution system investments** considered in emerging **proactive investment practices** (Section 4)

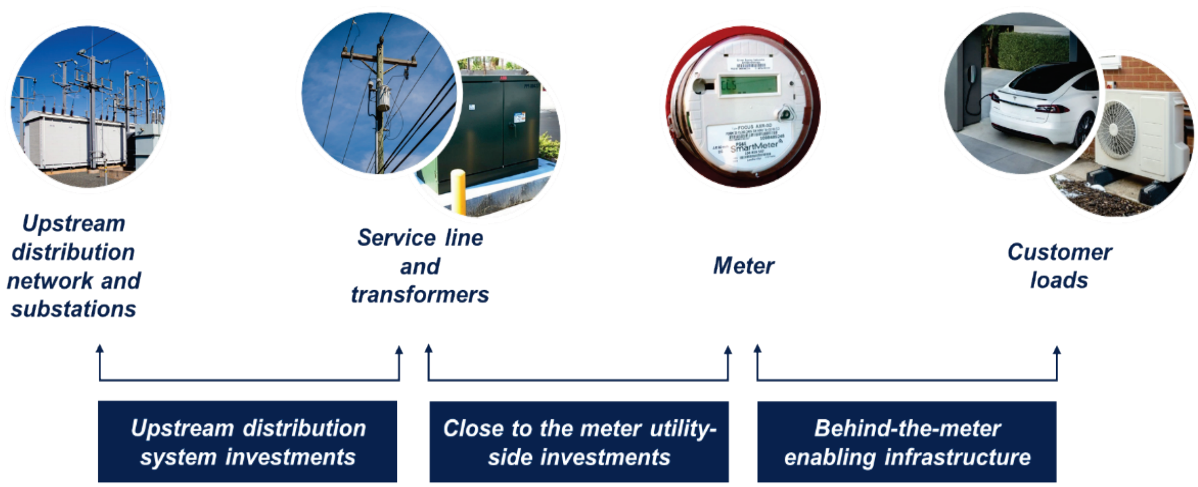


**Figure 1-2. Distribution system and electrification-driven load growth upgrades**

This report describes existing utility investment cost recovery and allocation approaches to demonstrate the range of industry practices to help inform commissions, state energy offices, and other stakeholders. We reviewed practices of regulated investor-owned utilities, though our findings may also be useful for publicly-owned utilities. The insights provided are grounded in existing practices and informed by a review of legislative and regulatory actions in a subset of states. Our review focused on actions related to distribution system infrastructure deployed up to and including the EV charging station for transportation electrification investments or up to and including the electrical panel for building electrification. End-use technologies often included in utility programs (e.g., many programs offer rebates for adopting a heat pump) were outside the scope of our analysis.

This report includes four additional sections. Section 2 focuses on the current practices for recovering and allocating utility electrification program costs. Utility programs play an important role in addressing market barriers and supporting market development, which can occur, for example, by focusing on customer segments facing greater technology adoption hurdles. These programs also impact utility costs and rates charged to ratepayers, requiring an ongoing balance between enabling technology and ensuring rate impacts are reasonable. As utilities' role in providing electrification programs continues to evolve and increase in scale (Brattle Group, 2021; Huether et al., 2022), it is important to understand existing practices that may support regulatory decision-making when considering utility proposals. This section reviews utility electrification programs in 13 U.S. states, including Arkansas, California, Colorado, Illinois, Massachusetts, Maryland, Michigan, Minnesota, North Carolina, Oregon, Pennsylvania, Rhode Island, and Washington. We reviewed program design elements that impact program costs. In this regard, we discuss the role of capitalization vs. expensing of behind-the-meter assets, the ability to exceed initially approved program budgets, and the role of program-specific rates (e.g., participation in time-of-use (TOU) rates) and load management measures (e.g., participation in demand response actions). Additionally, we provide insights on cost recovery and allocation approaches. For cost recovery, we discuss existing utility practices, including cost recovery through base rates, riders, or the use of direct cost assignment, and provide examples of regulatory decisions on utility cost recovery proposals. For cost allocation, we describe the range of methods across utility programs and provide insights into commission decisions. Lastly, we provide evidence of electrification-related reasonableness standards and considerations, which give insight into how states may provide guidance to determine if utility-proposed investments are just and reasonable.

Section 3 focuses on the current practice for recovering and allocating line extension costs due to electrification. Customers adding new loads to the system will likely need to consider whether their utility electric service is able to meet their needs. In some cases, customers may need a service upgrade, which may delay the ability to serve new loads and increase costs, acting as a barrier to electrification (Bastian & Cohn, 2022; Less et al., 2021). For instance, the need for an electric panel upgrade may indicate the need for an electric service upgrade (Shoshana et al., 2022). Line extension policies determine cost responsibilities between the utility and customers for utility side infrastructure needed to serve new loads and generally give customers an allowance to cover a portion of the line extension costs (Lazar et al., 2020; NARUC, 2021; Guldner & Grabel, 2008). Traditionally, these policies did not include electrification-specific considerations. However, policy goals and customer technology adoption are resulting in new line extension policy approaches with greater levels of support for electrification. This section reviews utility line extension policies in 13 U.S. states, including Arkansas, California, Colorado, Illinois, Massachusetts, Maryland, Michigan, Minnesota, North Carolina, Oregon, Pennsylvania, Rhode Island, and Washington. In this section, we characterize current line extension policies across a range of levels of support for electrification, from approaches where the customer adding new load would be responsible for all line extension costs to approaches where the utility covers all the costs, socializing them across ratepayers for cost recovery. For each level of support, we provide examples of utility practice and outline the main characteristics of their line extension policies. Additionally, we identify relevant dimensions regulators may consider when determining opportunities to reform line extension policies, including allowance support provided, asset scope, infrastructure utilization, equity, and future-proofing. Lastly, we describe pathways states may follow to pursue line extension policy reforms.

Section 4 focuses on emerging practices for recovering and allocating proactive distribution system costs due to electrification. Utilities and public utility commissions have traditionally followed a "just-in-time" distribution system investment strategy focused on addressing near-term grid needs, where sufficient visibility exists to ensure that investments result in assets that are utilized and that costs are reasonable. Forecasts of rapid load growth, in many regions driven by end-use electrification are motivating regulators and utilities to consider the role of proactive investments to ensure the distribution system can meet the needs of growing demand (EFI Foundation, 2024; Moran et al., 2023). Our review of state practices includes a range of legislative and regulatory actions taken in California, Colorado, Massachusetts, Minnesota, North Carolina, and New York. Proactively investing in distribution grid assets involves greater uncertainty than traditional utility investment practices and may require new regulatory approaches to ensure reasonable rates. This section outlines risk considerations, describes state practices, including legislative and regulatory actions, and provides a series of risk management options regulators may consider as part of their evolving toolkit of proactive investment enabling practices. The risk considerations discussed provide regulators with insights into the risks of investing following a just-in-time or proactive approach. We discuss state approaches across different stages of the process to enable proactive investments. Lastly, we outline risk management options across procedural, financial, and public policy domains.

Section 5 provides a summary of key considerations for regulators that emerge from our review.

# 2. Current practice for recovering and allocating utility program costs due to electrification

## 2.1 The role of utility electrification programs

Utilities have made significant investments in promoting the adoption of EV and other electric technologies through utility programs. For example, by the end of 2024, utilities had $6.6 billion approved for investments in transportation electrification (Atlas Public Policy, 2025). Some of these programs support enabling grid infrastructure. These programs support adoption among participating utility customers.

As the relevance and pace of electrification increase, the role of utilities in providing programs that support customer electrification is also growing (Brattle Group, 2021; Huether et al., 2022). Utility programs designed to enable electrification can support state goals related to decarbonization, increase grid flexibility, and provide customer savings (U.S. Department of Energy, 2024a). Utility programs can allocate financial resources with commission approval to support investments in enabling grid infrastructure and end-use technologies. Generally, these programs allocate funding to cover utility investments and provide financial support for customers through incentives or rebates (Cohn & Esram, 2022). To fund these programs, utilities typically raise revenue through dedicated charges on utility customer bills (i.e., through a rider mechanism) or by including those costs in electricity rates (i.e., through a general rate case proceeding).

Electrification programs may include investments in utility-side distribution system infrastructure and customer-side infrastructure, for example, up to the charging stations for EV-focused programs. The infrastructure provided through utility programs up to the charger for an EV program or up to the electrical panel for a building electrification program is often called "make-ready" infrastructure (Jones et al., 2018). Figure 2-1. illustrates make-ready infrastructure that may be offered to support EV load growth.

Utilities may structure electrification programs to focus on a specific sector, such as transportation or building electrification. Alternatively, utilities may act on multiple sectors through a program with a broader scope, as often seen in beneficial electrification programs (Cohn & Esram, 2022). Utilities may initiate programs due to legislative or regulatory requirements. Utilities may also, through their own motion, propose programs to regulators, for example, by including them in a general rate case application.

In this section, we focus on those utility programs that provide enabling grid infrastructure for electrification. We define "enabling grid infrastructure" as the infrastructure up to the charging station for programs supporting EV and up to the electrical panel for programs supporting building electrification. Utility electrification programs exclusively designed to support customer adoption of end-use technologies, such as the rebate for a heat pump or an electric vehicle, are out of scope for our review.

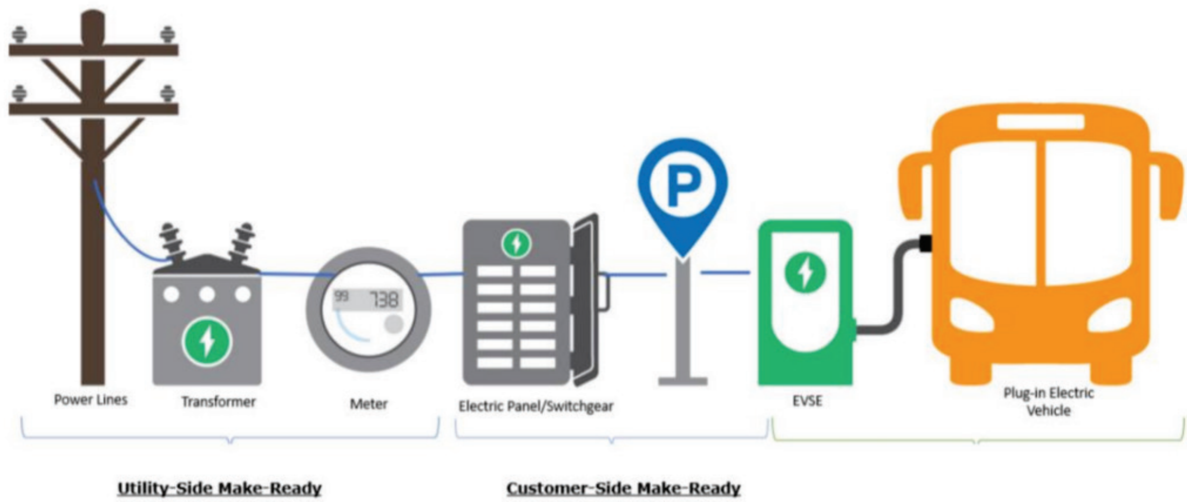


**Figure 2-1. Make-ready infrastructure for EV charging**

Source: From San Diego Gas & Electric (Lepre et al., 2022: p. 20)

We reviewed utility electrification programs across 13 states.[2] For each state, we reviewed utility programs from the largest regulated investor-owned utilities. In states with more than three investor-owned utilities, we limited our review to the three largest utilities. Through this review, we predominantly identified transportation electrification programs, as we found fewer building electrification and beneficial electrification programs that supported enabling grid infrastructure. This section provides insight into utility electrification program design, cost allocation and recovery, and cost reasonableness standards.

## 2.2 Utility electrification program design

### 2.2.1 General characteristics

Utilities typically structure electrification programs to address specific market needs. Utilities can structure their programs by defining the customer segments served, infrastructure offered, infrastructure ownership, and program duration.

*Customer segments*

Utility electrification-enabling programs address the needs of specific customer segments and may include subclasses of customers within residential and non-residential classes. For example, utilities generally include residential customers in their programs. However, utilities often structure programs to focus on specific residential customer segments. In California, the three large investor-owned utilities

[2] The 13 states are Arkansas, California, Colorado, Illinois, Massachusetts, Maryland, Michigan, Minnesota, North Carolina, Oregon, Pennsylvania, Rhode Island, and Washington. We chose these states in order to get a mix of geographies and also to consider states with varying levels of policy and programmatic focus on electrification. Our list includes most of the states that are very active in this area, but also some that are less active.

– Pacific Gas & Electric Company (PG&E),[3] Southern California Edison (SCE),[4] and San Diego Gas & Electric (SDG&E)[5] have targeted their transportation electrification programs to customers in multi-family residences to address the specific challenges these customers face in accessing EV charging infrastructure. For programs targeting non-residential customers, utilities support a range of different segments for this class, such as workplaces, commercial and industrial (C&I), education, transit, and fleets, as well as programs designed to support charging hubs. In some cases, utilities may set deployment targets for customer segments as part of their program design. For example, for residential customers, SCE Charge Ready 2 Program set a target for 30% of charging ports delivered through its program to be in multi-family residences.[6] Similarly, SDG&E , through its Power Your Drive Extension Program, set a target for 50% of its infrastructure to provide service to multi-family residences.[7] Deployment targets may also include equity considerations by requiring a specific share of the program's budget to be focused on disadvantaged communities.[8] For example, for residential customers, ComEd assigned 50% of its EV-related funding and 100% of its heat pump make-ready funding to environmental justice (EJ) income qualified customers.[9] Black Hills Energy assigned 15% of its program budget to fund dedicated income-qualified programs.[10] For non-residential customers, National Grid and Eversource set a target of locating 40% of ports deployed under its fleet make-ready offering in environmental justice communities.[11]

### *Infrastructure offered*

Utility programs vary in terms of infrastructure offered. As discussed above, our review focused on programs that provide enabling grid infrastructure (e.g., the infrastructure up to the charging station for transportation electrification programs or support for electrical panel upgrades). Out of scope in our review were programs focused exclusively on end-use technologies that can be included in the scope of a utility electrification program (e.g., rebate for a heat pump). Our findings predominantly relate to

[3] CPUC, 2022, Application 21-10-010, Decision Authorizing Pacific Gas and Electric Company's Electric Vehicle Charge 2 Program

[4] CPUC Decision 20-08-045, August 27, 2020, Decision Authorizing Southern California Edison Company's Charge Ready 2 Infrastructure and Market Education Programs

[5] CPUC Decision 21-04-014, April 15, 2021, Decision Authorizing San Diego Gas & Electric Company's Power Your Drive Extension Electric Vehicle Charging Program

[6] CPUC Decision 20-08-045, August 27, 2020, Decision Authorizing Southern California Edison Company's Charge Ready 2 Infrastructure and Market Education Programs

[7] CPUC Decision 21-04-014, April 15, 2021, Decision Authorizing San Diego Gas & Electric Company's Power Your Drive Extension Electric Vehicle Charging Program

[8] Utility terminology to communicate equity-focused program elements varies. For example, we found the term Disadvantaged Communities (DAC) in the regulatory filings reviewed for California and the term Equity Investment Eligible Community (EIEC) in Illinois.

[9] ComEd, 2023, Beneficial Electrification Plan, Compliance Filing May 2023

[10] Black Hills Energy, 2022, Ready EV Plan Black Hills' Transportation Electrification Plan

[11] MA DPU, 2022, Order December 30, 2022 on Docket 21-90 Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal, 21-91 Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal, 21-92 Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal

transportation electrification programs, with only a few examples of programs focused on electricity infrastructure for building electrification.

Utilities can design programs to support utility-side make-ready infrastructure, customer-side infrastructure, or end-to-end infrastructure. Utility-side make-ready infrastructure includes any assets to be sited in front of the meter. These assets may include service lines, transformers, and utility meters necessary to adapt utility-owned assets to enable customer electrification load growth. For example, Minnesota Power provided residential customers participating in its Residential Electric Vehicle Charging Rebate Program with a $500 rebate for installing a second service line. In this case, the utility requires customers to have a dedicated EV service line to participate in a dedicated EV TOU rate to encourage off-peak charging.[12] [13] Customer-side infrastructure includes any assets to be sited behind-the-meter, such as customer-side make-ready infrastructure for transportation and building electrification (e.g., wiring, conduit, panel upgrades) and charging stations. For example, Black Hills Energy provides support for panel upgrades for income-qualified customers.[14] Some utilities may structure programs to support end-to-end infrastructure when programs support infrastructure sited on both sides of the meter. For instance, ComEd provides make-ready infrastructure support on both the utility- and customer-side of the meter for C&I and public sector customers. In this program, make-ready infrastructure includes the secondary line from the transformer to the EV charging stub.[15]

### *Behind-the-meter infrastructure ownership*

Utilities typically own utility-side infrastructure up to the meter. Customer-side behind-the-meter infrastructure included in utility electrification programs may be owned by the customer, utility, or a third party. We found that most utility programs support customer ownership of behind-the-meter infrastructure, such as Indiana Michigan Power's offer of rebates for customer ownership of charging infrastructure.[16] Some programs offer support to either customer-owned or utility-owned infrastructure; a few programs only support utility-owned infrastructure. Third-party ownership is also an option. For example, DTE committed to facilitating third-party ownership of school bus chargers. In this case, the third party would have to agree with DTE’s scope of work for the pilot, including a vehicle-to-grid scope of work. [17] [18]

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[12] Minnesota Power, 2023, Minnesota Power Electric Rate Book, available at https://minnesotapower.blob.core.windows.net/content/Content/Documents/CustomerService/mp-ratebook.pdf at 20

[13] Minnesota Power, 2020, Docket 20-638, In the Matter of the Petition for Approval of Minnesota Power’s Portfolio of Electric Vehicle Programs

[14] Black Hills Energy, 2023, Compliance Filing Black Hills Energy Beneficial Electrification (BE) Plan 2023-2024

[15] ComEd, 2023, Beneficial Electrification Plan, Compliance Filing May 2023

[16] MPSC, 2020, In the matter of the application of Indiana Michigan Power Company for authority to increase its rates for the sale of Case No. U-20359 electric energy and for approval of depreciation
accrual rates and other related matters

[17] MPSC, 2023, Proposal for Decision, In the Matter of the Application of DTE Electric Company for authority to increase its rates, amend Case No. U-21297 its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.

[18] MPSC, 2023, Order, In the Matter of the Application of DTE Electric Company for authority to increase its rates, amend Case No. U-21297 its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.

Utilities may receive commission approval to own assets behind-the-meter. For instance, Xcel Energy received Commission approval to own direct current fast charging (DCFC) EV stations. In its decision, the Commission agreed with Xcel Energy that the sites selected for utility ownership were less likely to be served by private market providers and that forecasted EV traffic suggested the DCFC infrastructure would be valuable.[19] Similarly, Minnesota Power received Commission approval to own DCFC EV stations. However, in this case, the Commission recommended that the utility identify possible divestment strategies in the future.[20] Duke Energy Progress and Carolinas received approval to lease electric vehicle supply equipment to customers while retaining maintenance and operation responsibility.[21] In these cases, the Commission approved a program allowing the utility to own behind-the-meter assets. In the absence of a program, these costs would typically have to be borne by the individual customer acquiring the assets and not rate-based and socialized across ratepayers.[22] The regulator's rationale for allowing behind-the-meter utility ownership is often tied to the need to support an underdeveloped market segment (Orford, 2022). Table A-1 (Appendix A) provides insight into the types of behind-the-meter infrastructure ownership supported by the programs reviewed.

### 2.2.2 Capitalization and expensing of behind-the-meter assets

Utilities may seek regulatory approval to capitalize or expense costs related to behind-the-meter assets included in electrification programs.[23] Capitalization allows utilities to treat these investments as company assets and earn a rate of return during the asset's life. Utilities may seek approval to capitalize or expense costs related to either utility-owned assets or customer-owned assets funded by utility programs (e.g., rebates for EV chargers). For example, Xcel Energy received regulatory approval to capitalize the costs of utility-owned EV supply infrastructure and chargers and add those to the rate base.[24] Similarly, Black Hills Energy received regulatory approval to capitalize the costs of rebates for customer-owned EV chargers and earn a rate of return. In its decision, the Commission found that including these assets in the rate base and allowing a rate of return would incent the utility to pursue transportation electrification programs that include rebates as part of their design.[25] Expensing allows utilities to treat these costs as financial outlays in the year they occur and are not eligible to earn a rate of return. For example, ComEd received regulatory approval to expense behind-the-meter costs. In this

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19 MN PUC, 2022, In the Matter of Xcel Energy's Petition for Approval of Electric Vehicle Programs as part of its COVID-19 Pandemic Economic Recovery Investments, DOCKET NO. E-002/M-20-745

20 MN PUC, 2021, In the Matter of Minnesota Power's Electric Vehicle Charging Infrastructure Investment, DOCKET NO. E-015/M-21-257

21 NCUC, 2023, Docket No. E-7, Sub 1195, Order Dated August 8, 2023, available at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=b56ed5f6-8876-458f-8f67-bc06fb50e67f

22 Alternatively to rate basing across all ratepayers, utilities may own behind-the-meter infrastructure and recover recovery only from customers participating in the program. This is the case in the DEP DEC (NC) program described in the main text.

23 While there may be certain exceptions, in our review front-of-meter assets were always capitalized.

24 MN PUC, 2021, Order from July 2, 2021, In the Matter of Xcel Energy's Petition for Approval of a Multi-Dwelling Unit Electric Vehicle Pilot Program, Docket E-002/M-20-711

25 CO PUC, 2021, Order on August 10, 2021, In the Matter of the Application of Black Hills Colorado Electric, Llc for Approval Of its Transportation Electrification Plan, Ready EV, for Program Years 2021-2023 and for Related Tariff Approvals

case, ComEd had initially proposed to capitalize behind-the-meter program costs. The utility's proposal included an analysis demonstrating that capitalization would have smoothed rate impacts over a longer period of time (ten years) compared to expensing the assets, where all costs would be recovered from customers in a shorter time frame (three years). However, the Commission denied the request to capitalize behind-the-meter assets. The Commission concluded that while capitalization would mitigate the upfront costs for customers, it would also increase total program costs over time, as the utility would earn a rate of return on capitalized investments. [26] Similarly, National Grid received regulatory approval to expense behind-the-meter costs related to customer-side make-ready infrastructure. Initially, National Grid had proposed to capitalize behind-the-meter program costs. The Commission denied the request and indicated that capitalization of program costs did not result in sufficient benefits to ratepayers, considering the carrying cost associated with capitalization.[27] Table A-2 (Appendix A) provides insight into utility capitalization and expensing approaches of the programs reviewed as part of our analysis.

Capitalization of investments may be suitable if the legislature or commission determines the utility requires an incentive (i.e., earning a rate of return on capitalized behind-the-meter assets) to engage meaningfully in deploying electrification programs (Aas & O'Boyle, 2016; Bonbright, 1960; Khan, 1970; National Action Plan for Energy Efficiency, 2007).[28] [29] This may be the case for jurisdictions where utilities are taking their first steps to deploy electrification programs. Additionally, capitalization allows utilities to spread the program investments over the lifetime of the assets, resulting in a smaller immediate impact on rates. However, capitalization may also contribute toward a bias for proposing larger programs or for overspending on approved programs. Regulators can consider the impact on customers resulting from capitalizing investments, which increases the total costs for customers (Kihm et al., 2015). Capitalizing program costs means that future customers will pay for a portion of program costs, given that capitalized assets are likely to stay in the utility's rate base for longer than the program duration, thus resulting in the need to recover rate of return earnings or depreciation costs from customers. This may be an appropriate approach for jurisdictions seeking to promote investments to enable electrification load growth, as well as for any investments that benefit both existing and future customers. Expensing of investments may be a suitable approach for jurisdictions with more mature

[26] ICC, 2023, Order on March 23, 2023, Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX. Docket 22-0432

[27] MA DPU, 2022, Order December 30, 2022 on Docket 21-90 Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal, 21-91 Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal, 21-92 Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal.

[28] Colorado's SB 19-077 allowed utility transportation electrification programs to earn a return at the most recently commission-approved rate of return. The legislation allowed this return to apply to rebates provided to customers. Colorado's SB 19-077, available at https://leg.colorado.gov/sites/default/files/2019a_077_signed.pdf

[29] Chapter 4 of the National Action Plan for Energy Efficiency (2007) discusses the pros and cons of capitalizing or expensing utility costs. The examples given are related to energy efficiency program expenditures but provide relevant context for other types of utility programs, such as those included in this report.

utility electrification efforts. This approach may also contribute to containing total program costs, which are lower since no rate of return is earned on expensed costs (Advanced Energy Economy Institute, 2018). However, the immediate rate impact is greater, as utilities opting to expense program costs will recover all costs from their existing customers. This may be an appropriate approach for jurisdictions where historical utility investments to support electrification are already significant and where adding further costs onto the future rate base would result in unreasonable rates.

The impact of capitalization on rates depends also on the depreciation of costs, which reflects the loss of asset value that occurs over time (USAID, 2021). [30] The loss of value through the depreciation of an asset reflects an estimate of how much of the asset was used to create value for the utility in a year. Annual depreciation costs are part of the utilities' allowed revenue and are recovered through rates. The depreciation period used impacts how those costs are distributed over time. Longer depreciation periods result in smaller rate impacts over time while allowing the utility to earn a rate of return on non-depreciated capital for longer, increasing total costs for ratepayers.

We found examples of utility programs applying different depreciation periods for capitalized costs. For example, Xcel Energy and Black Hills Energy received regulatory approval to depreciate costs over ten years. In its proposal to the Commission, Xcel Energy recommended a ten-year amortization period, given that the rebates being capitalized focused on supporting the installation of EV chargers, which the utility expects to have a useful life of ten years. Xcel Energy argued that the proposed amortization period would align cost recovery for the chargers with the duration of the expected benefits the charges will provide,[31] such as utility revenue resulting from EV charging.[32] Following a different rationale, Black Hills Energy initially proposed a three-year amortization period to match the duration of their program.[33] However, the Commission required Black Hills Energy to use a ten-year amortization period to match the expected life of the assets. The Commission argued that the three-year amortization proposal lacked a compelling rationale to require ratepayers to pay the costs of the assets over a different time period than the assets are expected to provide benefits. In this case, the Commission argued that many Black Hills Energy customers, already exposed to relatively high rates, would benefit from lower immediate rate impacts, even if that results in higher total program costs.[34]

30 Utilities' allowed revenues include operational expenditures, amortizations, and return on capital. See USAID (2021) for more details on utility depreciation.

31 Xcel Energy, 2020, Docket 20A-0204, Direct Testimony and Attachment of Arthur P. Freitas on Behalf of Public Service Company of Colorado, in the matter of the application of Public Service Company of Colorado for approval of its 2021-2023 transportation electrification plan.

32 CO PUC, 2020, Order on December 23, 2020, In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021-2023 Transportation Electrification Plan.

33 Black Hills Energy, 2020, Docket 20A-0195E, Direct Testimony and Attachments of Patrick Grant Gervais ON BEHALF OF BLACK HILLS COLORADO ELECTRIC, LLC, in the matter of the verified application of Black Hills Colorado Electric, LLC for approval of its transportation electrification plan, Ready Ev, for program years 2021 –2023 and for related tariff approvals.

34 CO PUC, 2021, Order on August 10, 2021, In the Matter of the Application of Black Hills Colorado Electric, Llc for Approval Of its Transportation Electrification Plan, Ready EV, for Program Years 2021-2023 and for Related Tariff Approvals

### 2.2.3 Ability to exceed initially approved budget

Regulators may give utilities different degrees of flexibility to exceed their program budget, ranging from no flexibility to some predetermined level of flexibility (i.e., up to a certain share of the program budget) to the ability to request a budget increase subject to commission approval. Regulators may give no flexibility and order that a program budget cannot be exceeded. For example, SDG&E cannot exceed its Commission-approved budget, and as a result, no budget overruns may be recovered from ratepayers.[35] The Commission introduced this limitation, given the cost overrun of 56% in the previous pilot program. Regulators may give the utility the ability to exceed the program budget up to a cap. For instance, Xcel Energy and Black Hills Energy received regulatory approval to exceed their budget by 25% of the annual estimated program costs.[36] [37] This approach gives utilities certainty on the ability to manage budget overruns, as the cap was set by the commission when the programs were approved. Lastly, regulators may allow utilities to request a budget increase, to be decided on a case-by-case basis. For example, ComEd and Ameren may exceed the approved program budget, subject to Commission approval.[38] [39] This approach gives the utilities less certainty on their ability to incur budget overruns, given that the commission may deny a request to increase its budget.

The degree of flexibility granted to the utility impacts its ability to deliver on planned program outcomes when deployment costs change during implementation. A utility with greater flexibility to exceed its initially approved program budget may be able to deliver on planned program outcomes when program deployment costs increase. This could be the case when cost estimates used during program design and approval are lower than the actual costs due to changes in program technologies, installation costs, or program marketing, education, and outreach activities to recruit customers. However, greater flexibility may result in higher costs for ratepayers than initially approved by the commission and stakeholders. Regulators may consider the trade-offs between achieving program goals and impact on rates when considering budget flexibility.

### 2.2.4 Rate structure and load management

Utility programs may include design elements related to specific rates or load management measures that customers may be required to participate in. We found programs that included load management measures, programs that included specific rates, and programs that required both. Table A-3 (Appendix A) provides insight into the rate and load management requirements of the programs reviewed as part of our analysis.

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35 CPUC Decision 21-04-014, April 15, 2021, Decision Authorizing San Diego Gas & Electric Company's Power Your Drive Extension Electric Vehicle Charging Program

36 CO PUC, 2021, Order on August 10, 2021, In the Matter of the Application of Black Hills Colorado Electric, Llc for Approval Of its Transportation Electrification Plan, Ready EV, for Program Years 2021-2023 and for Related Tariff Approvals

37 CO PUC, 2020, Order on December 23, 2020, In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021-2023 Transportation Electrification Plan.

38 ICC, 2023, Order on March 23, 2023, Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX. Docket 22-0432

39 ICC, 2023, Order on March 23, 2023, Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX. Docket 22-0431

Utilities and regulators can consider the role of dedicated rate structures and load management measures when considering electrification program design. Including these elements in utility programs can contribute to enhancing program benefits for participating customers, ratepayers, and the grid. Dedicated rates can enable customers to access bill savings by shifting consumption to off-peak hours, which would also reduce strain on the distribution system during peak conditions and potentially reduce the need for capacity investments. Load management measures can reduce costs associated with serving new loads by reducing the need for infrastructure upgrades close to the meter, benefiting customers adding new loads by reducing cost and expediting the energization process. Load management can also reduce the need for upstream system upgrades benefiting all ratepayers.

Load management measures include utility measures to manage program-related loads to deliver grid services, such as shifting loads to specific times during the day to reduce peaks. Programs with load management measures include, for example, National Grid, which requires residential customers to enroll in a managed charging program. Customers can enroll in National Grid's ConnectedSolutions program or its off-peak charging rebate program.[40] Similarly, Eversource will consider deploying an energy management system to support EV charging for its public, workplace, and multi-family housing program participants. Deployment of an energy management system is determined on a case-by-case basis for each site and pursued if it would help reduce infrastructure costs.[41]

Specific rates include rates designed by the utility to incentivize program participants' electricity usage behavior, such as incentivizing off-peak EV charging for EV programs. Programs with specific rates, include, for example, Otter Tail Power , which implemented a TOU rate as part of its DCFC network. This rate charges DCFC users time-differentiated prices.[42]

Programs with load management measures and specific rates include, for example, PG&E, which uses automated load management to promote efficient use of grid infrastructure. Automated load management is used to share available electrical capacity among charging stations to avoid the

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[40] MA DPU, 2022, Order December 30, 2022 on Docket 21-90 Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal, 21-91 Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal, 21-92 Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal.

[41] MA DPU, 2022, Order December 30, 2022 on Docket 21-90 Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal, 21-91 Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal, 21-92 Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal.

[42] MN PUC, 2020, Order from October 27, 2020, In the Matter of Otter Tail Power Company's Request for Approval of Electric Vehicle Charging and Infrastructure Programs

installation cost of additional electrical capacity.[43] PG&E also requires customers to enroll under TOU or real-time rates.[44]

## 2.3 Utility electrification program cost recovery and allocation

### 2.3.1 Cost recovery

Cost recovery mechanisms establish how program costs are recovered from ratepayers (Costello, 2014). Through our review, we found programs recovering costs through base rates, riders, and direct assignment mechanisms. Table 2-1 provides examples of cost recovery mechanisms found across our sample of utility programs. We discuss program cost allocation in the following section (Section 2.3.2).

**Table 2-1. Utility program cost recovery mechanism**

| Cost recovery mechanism | | Utility (State) |
|---|---|---|
| **Base rates** | | PG&E, SCE, SDG&E (CA); Ameren, ComEd (IL); DTE, Consumers, I&M (MI); Xcel Energy, Minnesota Power, Otter Tail Power (MN); Rhode Island Energy (RI) |
| **Rider** | ***Use of a dedicated rider for electrification programs*** | Xcel Energy; Black Hills Energy, EV (CO); ComEd, make-ready infrastructure for non-residential EV-charging customers (IL); National Grid, Eversource (MA) |
| | ***Use of an existing rider not dedicated to electrification programs*** | Black Hills Energy, using Demand Side Management rider (CO), Until, using Grid Modernization Program rider (MA); Pacific Power, System Benefit Charge-combined with EE (OR) |
| **Direct cost assignment** | | ComEd, make-ready infrastructure for non-residential EV-charging customers (IL); DTE, residential home charger program (MI); Xcel Energy, residential program EV charger and installation costs (MN); Entergy (AR); DEC & DEP (NC) |

Base rates are the rates customers pay that are established through general rate case proceedings for utilities to recover the costs of supplying electricity to customers and earn a fair return on investment – the utilities' revenue requirement (Roe, 2023). To develop base rates, utilities conduct cost-of-service studies in which their revenue requirement is functionalized, classified, and allocated to customers. In the functionalization step, utilities distribute their revenue requirement across system functions (e.g., generation, transmission, distribution, customer service, public policy program costs, and general costs, etc.) After this step, utilities classify each function according to different factors causing the cost, which include demand, energy, and customer factors. Lastly, utilities allocate these costs to customer classes (e.g., residential, small commercial, etc.) using different allocation factors, such as class peak demand, and energy usage (Hendrickson, 2009). With this information utilities design rates for each class, which

[43] PG&E automated load management applies at all times to minimize the need for upgrades and reduce infrastructure costs. See PG&E, 2021, Application 21-10-010, Pacific Gas and Electric Company Electric Vehicle Charge 2 Prepared Testimony

[44] CPUC, 2022, Application 21-10-010, Decision Authorizing Pacific Gas and Electric Company's Electric Vehicle Charge 2 Program

may include fixed monthly charges ($) and variable charges (e.g., cents per kWh). Figure 2-2 provides an overview of a simplified rate-making process for investor-owned utilities.

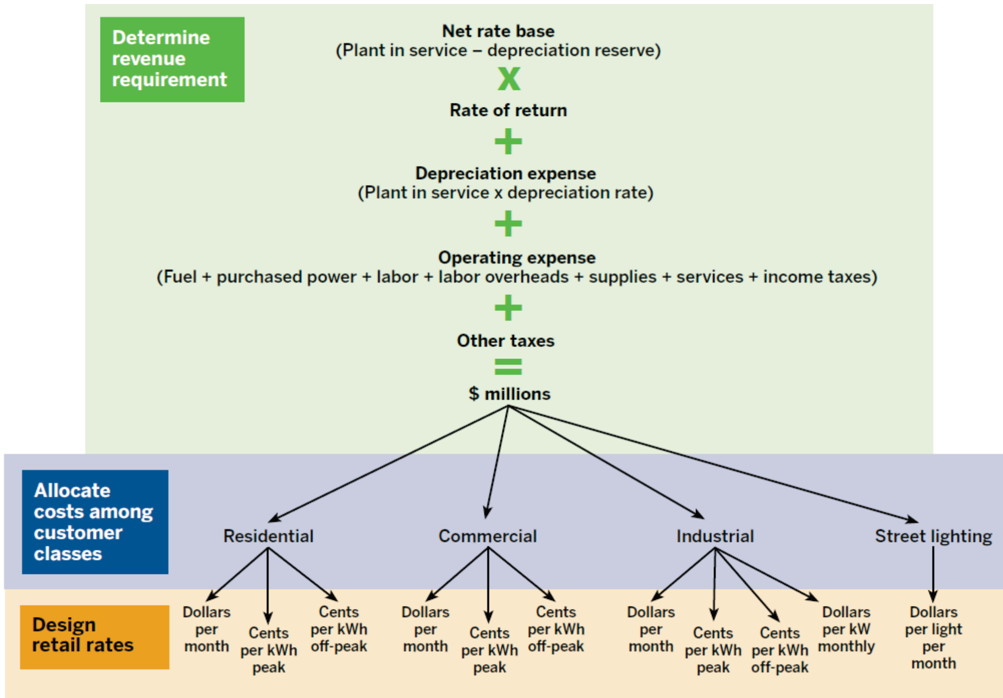


**Figure 2-2. Rate-making process**

Source: From Lazar et al. (2020: p. 15)

In our review, we found utility programs indicating cost recovery through distribution base rates for PG&E, SCE, SDG&E, ComEd, and Ameren.[45] We also found programs without a mention of how program costs flow into rates but acknowledging that program costs would be included in a future rate case for commission approval (e.g., DTE, Consumers, and I&M; Xcel Energy, Minnesota Power, and Otter Tail Power; and Rhode Island Energy.

Utilities' cost recovery through base rates depends on the mechanism approved by the commission and its design. For instance, in California, the Commission allows utilities to establish balancing accounts to track actual costs (Enerdynamics, 2025b), which may differ from the initially approved costs. Regulators base approved costs on estimates and projections to determine the revenue requirement. A balancing account may show an excess when the utility recovered more money from ratepayers than the actual costs it incurred or a deficit when the utility incurred more costs than it recovered from ratepayers.[46]

[45] Distribution base rates are set to recover utility revenue requirements related to maintaining, expanding, and modernizing the distribution system to deliver electricity to customers. Costs included in distribution rates may include substations, primary circuits, line transformers, secondary service lines, meters, and other utility expenditures associated with the distribution system activities.

[46] CPUC, 2021, Balancing Accounts Performance Audit San Diego Gas & Electric Company January 1, 2018, Through December 31, 2018, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/utility-audits--risk--and-compliance-division/reports/energy/2021/energy_2021-12-20_sdge_ba.pdf

SDG&E received Commission approval to track its electrification program spending via a one-way balancing account, which requires the utility to refund any overcollection from ratepayers but not to recover costs in excess of the approved budget," through which any program funds approved but not spent are returned to the ratepayer, and any spending over the budget is not eligible to be recovered from customers through rates and must be covered by shareholders. The Commission denied an initial utility request for a "two-way balancing account, which would have allowed it to recover costs greater than initially approved by the Commission (Enerdynamics, 2025b).

Riders are cost adjustment mechanisms established outside of general rate cases that allow utilities to begin cost recovery without having to wait for a future rate case. Initially used as fuel adjustment mechanisms in the 1970s, riders are now used for many cost categories, including electrification programs (Lazar, 2016). Utilities can use riders to track unexpected costs, and the charge resulting from the rider may be adjusted over time (e.g., quarterly or annually) (Faruqui, 2016). Riders or other cost adjustment mechanisms typically appear as a separate charge in the customer's electric bill. Utilities recovering electrification program costs through riders may create a dedicated rider for the associated electrification program or may use an existing rider previously approved by the commission. For example, Unitil received Commission approval to recover EV program costs through its existing Grid Modernization Program rider. In its decision, the Commission indicated that given the size ($1.02 million) and scope (residential and public charging) of the program, it would be inefficient for the utility and its customers to establish a new separate rider to recover program costs.[47] Xcel Energy and Black Hills Energy received Commission approval to recover costs using a dedicated rider – the Transportation Electrification Rider, which appears as a new line item on customer's bills. Colorado's legislation requiring Transportation Electrification Plans (Senate Bill (SB) 19-077) explicitly authorized the Commission to consider a dedicated rider for cost recovery.[48] Xcel Energy had initially proposed using an existing rider – the Demand Side Management Cost Adjustment rider – to recover costs, which would avoid adding another line item to customers' bills. However, the Commission denied this proposal due to transparency concerns raised by stakeholders and ordered a dedicated rider instead.[49]

Direct cost assignment may be used to recover costs related to infrastructure that are not used by other customers (NARUC, 1992). Through this approach, costs are recovered from an individual customer

[47] MA DPU, 2022, Order December 30, 2022 on Docket 21-90 Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal, 21-91 Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal, 21-92 Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal.

[48] State of Colorado, 2019, SB19-077, Concerning Measures that Affect the Development of Infrastructure Used by Electric Motor Vehicles, and, in Connection Therewith, Establishing A Process At The Colorado Public Utilities Commission Whereby A Public Utility May Undertake Implementation Of An Electric Motor Vehicle Infrastructure Program Within The Area Covered By The Utility's Certificate Of Public Convenience And Necessity, available at https://leg.colorado.gov/sites/default/files/2019a_077_signed.pdf

[49] CO PUC, 2020, Order on December 23, 2020, In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021-2023 Transportation Electrification Plan.

whose action created the cost. The utility invoices the customer for these costs, which are not included in the revenue requirement to determine base rates. For example, ComEd uses direct cost assignment to recover non-standard make-ready infrastructure costs from non-residential customers.[50]

For costs recovered through distribution rates and riders, utilities may pursue different cost allocation approaches, discussed in Section 2.3.2 below. For costs recovered directly from individuals through direct cost assignment, the total costs are recovered from the customer, often through a special facility charge by the utility. This special facility charge may be calculated based on the actual cost of the facilities installed or the average system costs of comparable facilities, and there is no allocation of costs across customers (Lazar et al., 2020; NARUC, 1992).

The commission can shape how utilities implement proposed utility cost recovery mechanisms, as discussed above (e.g., one-way vs. two-way balancing accounts or the use of existing vs. new riders). The commission can also determine whether a proposed mechanism is adequate. For example, ComEd proposed to create a new rider for cost recovery. The Commission denied this rider and ordered ComEd to recover costs through base rates. In its decision, the Commission indicated that ComEd had not sufficiently demonstrated that program costs were a result of unusual circumstances or that these costs were sufficiently difficult to control to justify a rider mechanism. The Commission determined that a rider could result in unreasonable rates and provide a disincentive for program cost control.[51] Similarly, Minnesota Power requested a new rider for cost recovery, which the Commission denied. The Commission held that Minnesota Power's cost recovery for its transportation electrification programs should be consistent with other utilities' cost recovery for similar programs through base rates.[52]

The cost recovery mechanism approved by the regulator may result in different incentives for the utility. For instance, using rates set in a general rate case may cause a lag in cost recovery for programs approved between rate cases (Beecher, 2016). This may incentivize the utility to manage costs efficiently between rate cases and execute programs within the approved budget resulting in more certainty on rate impacts (Costello, 2014).

Riders reduce cost recovery lag but may create a disincentive for utility cost control and may be subject to less regulatory scrutiny (Carroway et al., 2022; Costello, 2009, 2014). Regulators may consider the effectiveness of a rider proposal in achieving program goals and determine if it is an adequate cost recovery mechanism. Commissions may consider allowing cost recovery through riders in cases where the necessary utility investments are significant and not reflected in the company's rates approved in the previous rate case, and the utility has limited control over the timing requirements for those investments. This may be the case for electrification programs resulting from state legislation with

[50] ICC, 2023, Order on March 23, 2023, Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX. Docket 22-0432
[51] ICC, 2023, Order on March 23, 2023, Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX. Docket 22-0432
[52] MN PUC, 2021, Docket E-015/M-20-638, In the Matter of the Petition for Approval of Minnesota Power's Portfolio of Electric Vehicle Programs

timing requirements outside the utility's control.

### 2.3.2 Cost allocation

Cost allocation mechanisms establish how program costs are distributed across customer classes. Utilities use cost allocation factors across different cost categories (e.g., demand, energy, customer costs) to determine the costs applicable to each class (NARUC, 1992). The goal of cost allocation is to ensure costs are distributed across customer classes fairly and equitably. The process can be guided by the principles of cost causation (i.e., why are the costs necessary?), and costs follow benefits (i.e., which class benefits from the investments?) (Lazar et al., 2020). Table 2-2 provides details on the cost allocation methods found in our review, as well as definitions and illustrative examples of utilities using those methods.

**Table 2-2. Utility program cost allocation approach**

| Cost recovery | Cost allocation method | Definition | Examples |
|---|---|---|---|
| Base rates | ***Equal percentage of marginal cost*** | Program costs allocated based on a customer class's share of distribution marginal costs (Lazar et al., 2020). [53] | PG&E (CA)[54] |
| | ***Equal cents per kWh*** | Program costs allocated based on a customer class's share of energy usage (Enerdynamics, 2025d). | SCE[55] and SDG&E[56] (CA) |
| | ***Assigned to classes associated with the program's target customers*** | Program costs allocated directly to the customer class with which those costs are associated. For example, a program providing residential customers with make-ready infrastructure and Level 2 chargers would recover those costs from its residential class (Lazar et al., 2020). | Consumers (MI), Residential program "PowerMIDrive" costs allocated to residential class and commercial "PowerMIFLeet" costs allocated to commercial class[57] |
| | ***Cost allocator not found in program filing*** | For these cases, the cost allocator may be determined in a future filing or may be included in another filing we did not find in our docket review. | Ameren (IL); DTE, I&M (MI); Xcel Energy, Minnesota Power, Otter Tail Power (MN); Rhode Island Energy (RI) |
| **Riders** | ***Class non-coincident peak*** | Program costs allocated based on the ratio obtained from considering each customer class share of the sum of all customers' peak demands | Xcel Energy[58] and Black Hills Energy, EV program[59] (CO) |

[53] CPUC, Application 19-11-019. Decision Adopting Marginal Costs, Revenue Allocation, and Rate Designs For Pacific Gas And Electric Company, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M424/K378/424378035.PDF at 79

[54] PG&E, 2021, Application 21-10-010, Pacific Gas and Electric Company Electric Vehicle Charge 2 Prepared Testimony, at 152

[55] CPUC Decision 20-08-045, August 27, 2020, Decision Authorizing Southern California Edison Company's Charge Ready 2 Infrastructure and Market Education Programs

[56] CPUC, 2021, Application 19-10-012, Decision 21-04-014, Decision authorizing San Diego Gas & Electric company's power your drive extension electric vehicle charging program

[57] MPSC, 2023, Docket U-21224, Decision January 19, 2023, In the matter of the application of Consumers Energy COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief.

[58] CO PUC, 2021, Docket 20A-0204E, Decision C21-0017, In the Matter of the Application of Public Service Company of Colorado for Approval of Its 2021-2023 Transportation Electrification Plan

[59] CO PUC, 2021, Docket 20A-0195E, Decision R21-0486, In the Matter of the Application of Black Hills Colorado Electric, LLC for Approval of its Transportation Electrification Plan, Ready EV, For Program Years 2021-2023 and for Related Tariff Approvals

| | | |
|---|---|---|
| | (NARUC, 1992). | |
| ***Fixed percentage applied to customer total bill across classes*** | Program costs allocated by applying a fixed rate to customers' bills across customer classes. | Black Hills Energy, BE program (CO)[60] |
| ***Class-specific charge (cents/kWh) applied to customer bills*** | Program costs allocated through a class-specific charge (cents/kWh). The rate calculation uses the most recent Commission-approved distribution revenue allocators. | National Grid[61] [62] and Eversource[63] [64] (MA)<br><br>Unitil (MA) uses a simplified version of this method by combining similar classes into class groups and applying the rider percentage to those groups.[65] |

The programs in our sample include a range of cost allocation approaches. For example, SCE and SDG&E allocate costs using an equal cents per kWh method. This method divides the costs of an investment across customer classes based on the total units of energy each class is expected to consume (Enerdynamics, 2025d). However, both utilities had initially requested to allocate program costs using distribution cost allocators determined in its most recent rate case, which the CPUC denied.[66] SCE's distribution cost allocator is structured to recover peak and nonpeak load marginal costs. Peak load-related marginal costs are allocated based on the customer class's contribution to peak load. Non-peak load-related marginal costs are allocated based on the customer classes' effective demand.[67] In its decision, the Commission recognized concerns raised by intervenors in the proceeding, indicating that using a distribution allocator would contribute to an unfair cost allocation and place a greater burden on residential customers.[68] Intervenors discussed that an equal cents per kWh approach would:[69]

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[60] Black Hills Energy, 2018, Schedule Of Rates, Rules and Regulations for Electric Service, available at https://www.blackhillsenergy.com/sites/blackhillsenergy.com/files/bhe-coe-rates-tariff.pdf at 78

[61] National Grid, 2024, M.D.P.U. No. 1560 Electric Vehicle Program, available at https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/ev_adjmt_prov.pdf

[62] National Grid's distribution revenue requirement allocation is discussed in the utility's most recent rate case in Docket 23-150, Pre-Filed Direct Testimony of Melissa A. Little and Howard S. Gorman, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18228349 at 23

[63] Eversource, 2023, M.D.P.U. No. 78A Electric Vehicle Program, available at https://www.eversource.com/content/docs/default-source/rates-tariffs/mdpu-number-78a.pdf?sfvrsn=122a585d_1

[64] Eversource's distribution revenue requirement allocation is discussed in the utility's most recent rate case in Docket 22-22, November 20, 2022 DPU Order, Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/15824195 at 481

[65] Unitil, 2024, Grid Modernization Factor, available at https://unitil.com/sites/default/files/2024-01/E_GMF.pdf at 7

[66] CPUC Decision 20-08-045, August 27, 2020, Decision Authorizing Southern California Edison Company's Charge Ready 2 Infrastructure and Market Education Programs

[67] Public Advocates Office, 2018, Testimony on Southern California Edison Company's Application For Approval Of Its Charge Ready 2 Infrastructure And Market Education Programs, available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1806015/1816/247361422.pdf

[68] TURN, 2019, Opening Brief of the Utility Reform Network on Southern California Edison's Charge Ready 2 Infrastructure and Market Education Programs

[69] CPUC Decision 20-08-045, August 27, 2020, Decision Authorizing Southern California Edison Company's Charge Ready 2 Infrastructure and Market Education Programs

- Ensure all customers pay equally for the climate change and air quality benefits resulting from the program
- Ensure consistency with other public purpose programs implemented by regulated utilities in California
- Ensure cost allocation reflects policy goals as the primary driver of investment. [70]

Table 2-3 below presents SCE's cost allocation difference across customer classes in California using a distribution cost allocator or an equal cents per kWh allocator. The distribution cost allocator would result in the residential class paying 50.4% of the costs, while the equal cents per kWh allocator would result in 33.6%.

**Table 2-3. SCE Cost allocation for the Charge Ready 2 program**

| Distribution and Equal Cents (i.e., System Sales) Allocations by Rate Group[a] | | |
|---|---|---|
| | Distribution[b] | Equal Cents per kWh (System Sales)[c] |
| Residential | 50.4% | 33.6% |
| Small Commercial | 8.1% | 7.4% |
| Medium/Large Commercial & Industrial | 38.2% | 54% |
| Agricultural | 3.1% | 4% |
| Streetlighting | 0.2% | 0.9% |
| Total | 100% | 100% |

a: See Table 2-2, Public Advocates Office, 2018, Testimony on Southern California Edison Company's Application For Approval Of Its Charge Ready 2 Infrastructure And Market Education Programs, available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1806015/1816/247361422.pdf
b: A.17-06-030, Motion of Southern California Edison Company (U 338-E) And Settling Parties for Adoption of Revenue Allocation Settlement Agreement, Attachment A "Marginal Cost and Revenue Allocation Settlement Agreement", Page 14. See "Capped" Distribution allocation for residential.
c: A.17-06-030, Motion of Southern California Edison Company (U 338-E) And Settling Parties for Adoption of Revenue Allocation Settlement Agreement, Attachment A "Marginal Cost and Revenue Allocation Settlement Agreement", p. 14. "NDC and PUCRF are allocated to all retail customers on an equal ¢/kWh basis." Dated July 3, 2018.

Source: Adapted from The Utility Reform Network[71]

Through our analysis, we found different cost allocation methods approved by regulators to support the reasonable distribution of costs. For example, Xcel Energy received regulatory approval to distribute costs based on each class non-coincident peak, which the Commission considered reasonable.[72] The class non-coincident peak method allocates costs based on the ratio obtained from considering each

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70 Public Advocates Office, 2018, Testimony on Southern California Edison Company's Application for Approval Of Its Charge Ready 2 Infrastructure And Market Education Programs, available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1806015/1816/247361422.pdf

71 Adapted from TURN, 2019, Opening Brief of the Utility Reform Network on Southern California Edison's Charge Ready 2 Infrastructure and Market Education Programs at 35

72 CO PUC, 2020, Order on December 23, 2020, In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021-2023 Transportation Electrification Plan.

customer class's share of the sum of all customers' peak demands, regardless of when it occurs for a specific period (Kurnik et al., 2017; NARUC, 1992). Similarly, PG&E received Commission approval to allocate costs using an equal percentage of marginal cost method, which the Commission found reasonable for balancing efficiency and equity in cost allocation.[73]

Utilities and regulators may apply cost allocation methods approved in the most recent rate cases and defer to the process through which the commission and intervenors vet rate cases instead of including cost allocation as an issue to be addressed in program-focused proceedings, which focus on a specific set of investments and lack the more comprehensive consideration of the utility's costs (Pollock, 2010). For example, Black Hills Energy received Commission approval to allocate costs using a class non-coincident peak method approved in its more recent rate case. In its decision, the Commission indicated that deferring to cost allocation methods decided in rate cases ensured that Black Hills would allocate costs based on a method carefully evaluated by the Commission.[74] Similarly, National Grid,[75] Eversource,[76] and Unitil[77] apply their most recent distribution allocator approved in a rate case to determine the class-specific charges to recover program costs.

## 2.4 Utility electrification program reasonableness standards

Commissions are responsible for ensuring that utility rates are just and reasonable. This requirement is often included in statutes outlining the role of commissions and may also be part of commissions' mission statements (U.S. Environmental Protection Agency, 2010; Zitelman & McAdams, 2021). The application of just and reasonable as a standard aims to balance the interests of the utility and its shareholders (e.g., access to a fair rate of return and recovery of prudently incurred costs) with the interests of customers (e.g., access to safe, adequate, and reliable service at fair rates that reflect the quality of the service obtained) (Beecher, 2013; Guernsey, 1928; McDermott, 2012). In commission proceedings, the application of the just and reasonable standard is shaped by precedent (Isser, 2015), the intervenors' testimony submitted in regulatory proceedings and the commissioners' experience. Regulators may also consider other factors when determining reasonableness, such as Bonbright et al.'s attributes for setting sound utility rates (see Text Box 2-1) (Bonbright et al., 1988). The process for determining reasonableness is supported by a structured administrative proceeding where the utility, commission, and other interested parties establish a record through testimony and participation in hearings. Regulators apply just and reasonable standards at their discretion, considering the evidence in proceedings and established regulatory practices (Chan & Klass, 2022; Kihm et al., 2017). This discretion results in a zone of reasonableness when applying the standard, in which a range of rates and utility

[73] CPUC, Application 16-06-013, Decision On Pacific Gas And Electric Company's Proposed Rate Designs And Related Issues, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M221/K552/221552311.PDF at 22
[74] CO PUC, 2021, Docket 20A-0195E, Decision R21-0486, In the Matter of the Application of Black Hills Colorado Electric, LLC for Approval of its Transportation Electrification Plan, Ready EV, For Program Years 2021-2023 and for Related Tariff Approvals
[75] National Grid, 2024, M.D.P.U. No. 1560 Electric Vehicle Program, available at https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/ev_adjmt_prov.pdf
[76] Eversource, 2023, M.D.P.U. No. 78A Electric Vehicle Program, available at https://www.eversource.com/content/docs/default-source/rates-tariffs/mdpu-number-78a.pdf?sfvrsn=122a585d_1
[77] Unitil, 2024, Grid Modernization Factor, available at https://unitil.com/sites/default/files/2024-01/E_GMF.pdf at 7

investments may be considered reasonable (LeBel et al., 2023).

This reasonableness standard applies to all utility investments (Alliance for Transportation Electrification, 2023; Beecher, 2013; Jones et al., 2018), including the programs reviewed in this report. Through our review, we identified examples of jurisdictions adding specific guidance to determine whether proposed utility electrification-related investments are reasonable. We interpret these as approaches to reduce ambiguity in the application of the reasonableness standard (Isser, 2015), and provide clarity for regulators making decisions on utility proposals and for utilities developing investment strategies and submitting program applications to enable electrification. Table A-4 (Appendix A) provides a summary of the commission language related to reasonableness standards, including general standards outlining the commission's role in ensuring just and reasonable rates, as well as electrification-specific reasonableness guidance for the states in our sample, when available.

States may adjust their statutes to provide additional guidance for regulators to determine reasonableness. For example, in California, SB 350[78] required the Commission to order utilities to submit transportation electrification program proposals.[79] The law gave the Commission authority to approve utility programs and investments in transportation electrification as long as they don't compete unfairly with non-utility businesses, include performance accountability measures, and are in the interests of ratepayers. The law also amended the public utility code to provide additional guidance for regulators to determine the interests of ratepayers, which requires utility investment proposals to meet the just and reasonable standard.[80] Per the statute, programs and investments must contribute to safer or less costly utility services and deliver customer benefits, including energy efficiency of travel, reduced air pollution, and economic development.[81]

[78] State of California, 2015, SB-350 Clean Energy and Pollution Reduction Act of 2015, available at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

[79] State of California, 2015, SB-350 Clean Energy and Pollution Reduction Act of 2015, available at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350 at Section 740.12

[80] State of California, 1977, Public Utilities Code, Section 451, available at https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=1.&title=&part=1.&chapter=3.&article=1.

[81] For the complete list of benefits considered to determine ratepayer interest see: State of California, 2015, SB-350 Clean Energy and Pollution Reduction Act of 2015, available at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350 at Section 740.8

**Text Box 2-1. Bonbright et al.'s attributes for setting sound utility rates**

Bonbright et al.'s attributes provide regulators with factors to consider when determining the reasonableness of proposed utility rates. The list below is a direct quote from Bonbright et al.'s 1988 Principles of Public Utility Rates book.

*"Revenue-related Attributes:*

*1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.*

*2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.*

*3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity. (Compare "The best tax is an old tax.")*

*Cost-related Attributes:*

*4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:*

*(a) in the control of the total amounts of service supplied by the company;*

*(b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).*

*5. Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities).*

*6. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away un economically from an incumbent by a potential entrant).*

*7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).*

*8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.*

*Practical-related Attributes:*

*9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.*

*10. Freedom from controversies as to proper interpretation."*

Source: From Bonbright et al. (1988: p. 383-384)

States may limit the allowable rate impact from electrification investments to support reasonableness determinations by establishing a cost cap determined as a percentage of the utility's allowed revenue requirement. This approach provides utilities with a signal of the scale of programs that may be deemed reasonable. It provides legislators with the ability to encourage utility investment in electrification while protecting customers from unreasonable rate increases. For example, in Washington, the legislature set a cap of 0.25% of the utility's total annual revenue requirement on utility expenditures for electric vehicle charging infrastructure.[82] In Colorado, the legislature required that utility transportation electrification plans costs not exceed 0.5% of the total annual revenue requirement.[83] Similarly, in Illinois, the legislation requires that the cost of a beneficial electrification plan not exceed 1% of the total annual revenue requirement.[84]

States may establish guidance for regulators to ensure utility electrification programs address market gaps and are not taking on activities that other businesses are well-positioned to develop. For example, in Massachusetts, the Department of Public Utilities established that utility transportation electrification proposals must address a market need that the non-utility market likely will not, and also that proposals must not hinder the development of the non-utility EV charging market.[85]

States may also add specific expectations or requirements for utility electrification investment proposals, which can support regulatory decision-making. For example, in Minnesota, the MNPUC established that utility transportation electrification proposals must include a cost-benefit analysis for proposals that involve significant investments,[86] evaluation metrics, and expected outcomes for pilots.[87] Similarly, Illinois legislation established a set of reasonable expectations for beneficial electrification plans to maximize cost savings and rate reductions to ensure all ratepayers benefit, stimulate innovation and competition, and support the efficient and effective use of the grid.[88]

States may also consider specific criteria to guide reasonableness decisions. For example, SCE and SDG&E received regulatory approval on a set of *per se* reasonableness metrics that, if met, would result in program costs within the specified budget being considered reasonable. As a result, the utilities would not have to offer any further justification to determine program reasonableness and would only be subject to a review of the prudent administration of the approved program. However, if the *per se* metrics are not achieved, the utility must include the program costs as part of its next general rate case for commission review of reasonableness. The Commission recognizes that unforeseen challenges may

[82] State of Washington, 2019, An Act Relating to advancing green transportation adoption, available at https://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session%20Laws/House/2042-S2.SL.pdf?cite=2019%20c%20287%20s%206

[83] State of Colorado, 2018, Senate Bill 19-077, Transportation Electrification Plans, available at https://leg.colorado.gov/sites/default/files/2019a_077_signed.pdf

[84] State of Illinois, 2021, Climate and Equitable Jobs Act, available at https://epa.illinois.gov/content/dam/soi/en/web/epa/topics/ceja/documents/102-0662.pdf

[85] MA DPU, 2014, Docket 13-182-A, Investigation by the Department of Public Utilities upon its own Motion into Electric Vehicles and Electric Vehicle Charging, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9233599

[86] The level of investment was not specified in this case, giving the commission discretion to determine when a proposal constitutes a significant investment.

[87] MN PUC, 2019, Docket 17-879, In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, available at https://www.edockets.state.mn.us/documents/%7B10BBAA68-0000-C413-9799-DF3ED0978E75%7D/download?contentSequence=0&rowIndex=7

[88] State of Illinois, 2021, Climate and Equitable Jobs Act, available at https://epa.illinois.gov/content/dam/soi/en/web/epa/topics/ceja/documents/102-0662.pdf

occur during program implementation and gives the utility the opportunity to request changes to the *per se* metrics.[89] [90] Text Box 2-2 includes details on the metrics approved by the Commission.

Regulatory reasonableness standards are connected to the commission's mandate to ensure ratepayers pay just and reasonable rates. In our review, we found examples illustrating how some states have implemented a range of dedicated approaches to support just and reasonable determinations for electrification programs. These approaches build on the well-established requirements for commissions to ensure just and reasonable rates. State guidance for electrification-related reasonableness decisions may reduce ambiguity associated with the application of the just and reasonable standard for new utility activities enabling load growth (Isser, 2015).

**Text Box 2-2. *Per se* reasonableness standards for SCE and SDG&E**

**SCE's *per se* reasonableness metrics – Charge Ready 2 Program**

*"SCE's costs will be considered per se reasonable provided:*
*(1) at least 15 percent of Make-Ready Expansion ports are under the site host ownership option;*
*(2) the Own and Operate program is capped at 2,500 ports for MUDs in DACs;*
*(3) a minimum of 30 percent of the Make-Ready Expansion ports are located at MUDs;*
*(4) a minimum of 50 percent of the Make-Ready Expansion ports are located within DAC;*
*(5) SCE does not exceed an average per port cost of $15,000 for the Make-Ready Expansion Program;*
*(6) the budget spent on DCFCs is limited to $13.9M, as described in Appendix A, with at least 30 percent of ports located in DACs and 25 percent serving MUDs; and*
*(7) the New Construction Rebate Program is limited to $54M, at no more than $3,500 per port."*[91]

**SDG&E *per se* reasonableness metrics – Power Your Drive Extension Program**

*"Costs incurred for PYD2 up to the authorized level will be considered per se reasonable provided:*
*(1) at least 50 percent of sites are in underserved communities;*
*(2) at least 50 percent of sites are at MUDs or sites serving MUDs;*
*(3) at least 20 percent of sites have customer-side make-ready infrastructure owned by the customer;*
*(4) SDG&E owns EVSEs only in MUDs located in underserved communities; and*
*(5) SDG&E does not exceed an average per port cost of $15,000."*[92]

DACs: Disadvantaged communities; MUDs: Multi-unit dwellings; DCFC: Direct Current Fast Charging; EVSE: Electric vehicle supply equipment

[89] CPUC Decision 20-08-045, August 27, 2020, Decision Authorizing Southern California Edison Company's Charge Ready 2 Infrastructure and Market Education Programs
[90] CPUC Decision 21-04-014, April 15, 2021, Decision Authorizing San Diego Gas & Electric Company's Power Your Drive Extension Electric Vehicle Charging Program
[91] CPUC Decision 20-08-045, August 27, 2020, Decision Authorizing Southern California Edison Company's Charge Ready 2 Infrastructure and Market Education Programs
[92] CPUC Decision 21-04-014, April 15, 2021, Decision Authorizing San Diego Gas & Electric Company's Power Your Drive Extension Electric Vehicle Charging Program

# 3. Current practice for recovering and allocating line extension costs due to electrification

Line extension policies specify the utility's and the customer's responsibilities for the costs of utility side infrastructure needed to enable new loads to connect to the electric distribution system. Some utilities have recently received regulatory approval to modify their line extension policies to support electrification-related policy goals. This section describes current utility practices on cost allocation in electricity line extension policies. We present existing utility practices across categories according to the extent to which line extension policies support electrification. Greater levels of support result in greater socialization of line extension costs across utility customers.

This is followed by a menu of options for policymakers and regulators considering the role of line extension policies to enable electrification. Lastly, we identify pathways states can consider to pursue line extension policy reforms.

## 3.1 What is a line extension policy?

Utilities implement line extension policies through tariffs. These policies lay out the utility and customer roles and responsibilities for extending or upgrading utility distribution system infrastructure in front-of-the-meter to deliver electricity to serve customers' loads, including how costs for the connection will be shared between the utility and customer (Lazar et al., 2020). Line extension policies primarily support service requests from new customers. However, they also pertain to existing customers in need of a service upgrade to accommodate additional load. Text Box 3-1 illustrates the line extension process for new construction for Colorado's Xcel Energy.

Line extension policies emerged from the need to standardize how new loads connect to the distribution system to receive electric service (Guldner & Grabel, 2008). Generally, a line extension policy specifies (NARUC, 2021):

- The customer classes subject to the policy.
- How the costs of the line extension are determined.
- Any line extension allowances available to customers to offset all or part of their costs (see Section 3.2).
- How customers pay for any line extension costs.
- Any refunds for paid costs that customers may become eligible for (see Section 3.3).

**Text Box 3-1. Colorado's Xcel Energy electric service installation process**

Customers in Xcel Energy's service territory go through a process involving various stages related to identifying, developing, and delivering electric service.[93] The customer initiates this process through an application, which identifies load needs and site characteristics. The utility reviews the application and leads the engineering design work to provide electric service. If necessary, The customer pays for related costs, following Xcel's line extension policy requirements, and scheduling. The process concludes with construction and meter installation. Figure 3-1 below provides a timeline perspective of this process, as well as the activities included in each stage, including customer and utility responsibilities for each activity.

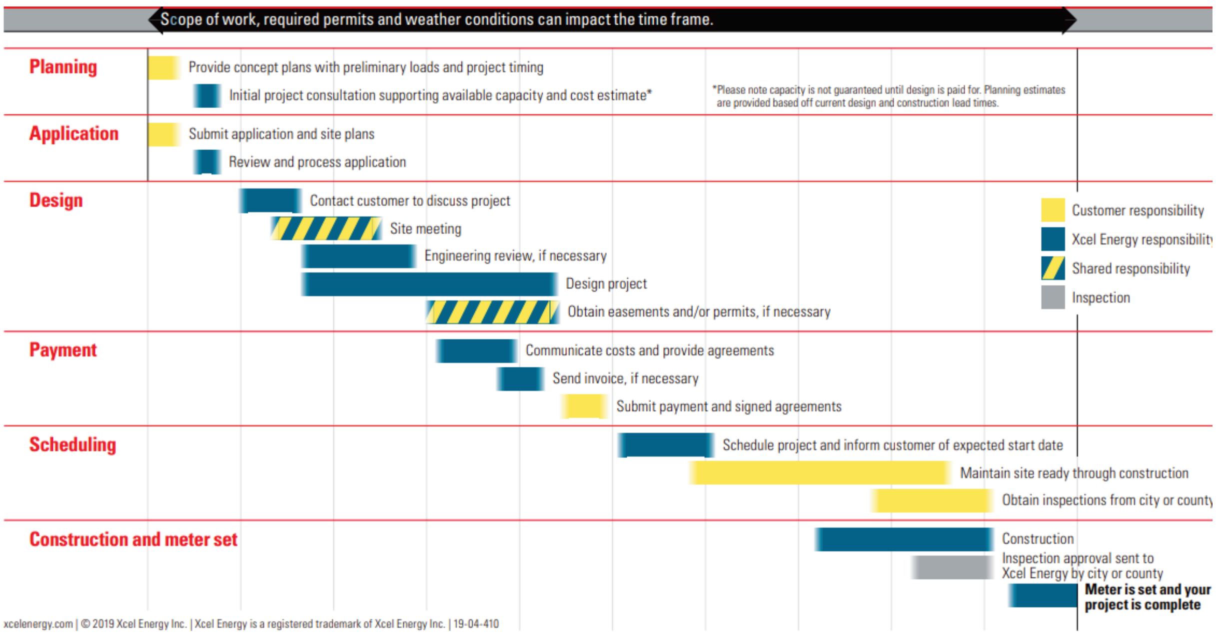


**Figure 3-1. Xcel Energy's process timeline**

Source: From Xcel Energy[94]

Typically, commissions require utilities to include line extension policies in their tariffs.[95] Line extension policies are state- and utility-specific and subject to regulatory oversight. The utility typically provides customers with an allowance toward the costs necessary to extend the electric distribution system to

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93 Xcel Energy, 2019, Docket 18AL-0862G Rebuttal Testimony and Attachment of Mary J. Woolf, Hearing Exhibit 104, available at https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=904024&p_session_id=

94 Adapted from Xcel Energy, 2019, Rebuttal Testimony and Attachment of Mary J. Woolf, Installing and connecting service diagram, Attachment MJW-R-1, Proceeding Nos. 18AL-0852E and 18AL-0862G, Hearing Exhibit 104, available at https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=904025&p_session_id=

95 State statutes may also establish line extension policies. For example, see California's Public Utility Code, "Section 783 - Rules governing extensions of service to new residential, commercial, agricultural and industrial customers", available at https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=783. Similarly, see New York's Consolidated Law, "Section 12, Gas and electricity must be supplied on application, Transportation Corporations (TCP) Chapter 63, Article 2", available at https://www.nysenate.gov/legislation/laws/TCP/12

serve new loads. The cost to provide line extensions is generally case-specific and requires the customer to engage with the utility to obtain an estimate.

Line extension policies also exist for gas infrastructure (Advanced Energy United, 2023; Costello, 2013). Our focus in this report is on line extension policies for electric service.

Utilities are able to provide line extension allowances due to the expected increase in electricity sales resulting from a new customer connection, which may result in downward pressure on rates for all customers (Advanced Energy United, 2023; Costello, 2013). Generally, these allowances are tied to expected utility revenue obtained through a new connection or upgraded service, resulting in greater electricity sales (Lazar, 1992). The line extension allowance included as part of the policy defines how much of the connection costs a utility will cover, with costs exceeding the allowance being the customer's responsibility. Customer costs related to line extensions are often referred to as contributions in aid of construction, which represent customer payments to be used for deploying utility infrastructure to obtain or upgrade electric service (Levinson & Schifrin, 2023).[96] The line extension allowance may be sufficient to fully cover the costs associated with the necessary upgrades in some cases, and no contribution in aid of construction is then necessary (McAllister et al., 2019). Utilities recover their share of the costs covered through allowances through base rates. Some electric utilities, such as cooperatives, may not provide allowances (McAllister et al., 2019).

Utilities follow different approaches to establish their allowances across customer classes. Given these different approaches, allowances from different utilities can be difficult to compare. We describe these approaches in Table 3-1 below and provide state examples in Section 3.2.2.

**Table 3-1. Utility approaches to set line extension allowances**

| Allowance approach | Description |
|---|---|
| **Cost** | Utilities can set a customer class-specific maximum dollar amount for the allowance. Customers are responsible for costs exceeding the allowance. |
| **Distance** | Utilities can set a maximum line distance. The distance cap may vary for overground and underground utility infrastructure. Customers are responsible for any costs necessary for assets that extend beyond the utility distance cap. |
| **Assets** | Utilities can establish a predefined set of assets the utility will provide. This may be established as segments of wire or the number of utility poles to be provided. Customers are responsible for covering the costs of additional assets beyond those predefined in the line extension policy. |
| **Expected revenue** | Utilities can set a customer-specific allowance cap based on the projected revenue expected by serving new loads. Customers are responsible for any costs exceeding the utility’s cap. |

[96] See for example MN Department of Commerce, Contributions in Aid of Construction For Utility and Pipeline Companies, available at https://www.revenue.state.mn.us/contributions-aid-construction

## 3.2 Line extension policies and electrification

Traditionally, line extension policies did not include specific criteria or provisions related to electrification. However, policy goals related to electrification and growth in customer demand are driving changes to this traditional approach (Hartnack & Hitchcock, 2023). Some recently updated line extension policies now provide different levels of support to customers who install electric technologies, predominantly for transportation electrification to enable EV charging. These changes generally provide higher allowances or full coverage for costs needed to upgrade electric service to connect new electrified loads. Higher allowances may be implemented to align utility practices with state policy goals ,[97] to encourage utility load growth through service upgrades that enable greater utility sales and put downward pressure on rates or as part of utility electrification programs (Jones et al., 2018).[98] In some instances, utilities require separate metering for the new load, such as separately metered EV chargers, or require that most of the load served under the service upgrade be for EV charging - examples, Examples of these cases are described below.

From reviewing utility line extension practices in 13 states, we defined four categories, presented in order of increasing level of support for customers using a line extension request for an electrification-related need (see Figure 3-2). Line extension policies with greater utility support result in greater socialization of costs, as the costs covered by the utility are recovered from ratepayers.

We only review utility policies that permit a customer to connect new load. There may be instances where a utility will not allow a customer to connect new loads timely even if the customer is willing to pay the full cost of doing so, as the utility may be unable to make all the grid upgrades needed to supply some loads in the timeframe required for those loads to come online.

### 3.2.1 Category A – Customer pays all the costs

Category A represents the lowest level of support for the cases when customers are responsible for all the costs resulting from a line extension necessary to serve an electrified load. This may be the case when the line extension policy includes eligibility criteria that prevent the customer from accessing the allowance. For instance, a line extension policy may require a load to be considered permanent to be eligible for an allowance, and the definition of permanent load may not include electric vehicle charging loads.

[97] For example, California's decision to consider residential line extensions for EV charging as a common facility cost was guided by the state's policy goals to encourage transportation electrification to contribute to reducing greenhouse gas emissions. See CPUC, 2011, Decision 11-07-029 Phase 2 decision establishing policies to overcome barriers to electric vehicle deployment and complying with public utilities code section 740.2, available at https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/139969.PDF

[98] Section 3.2.3. provides examples of greater line extension allowances implemented as part of utility programs.

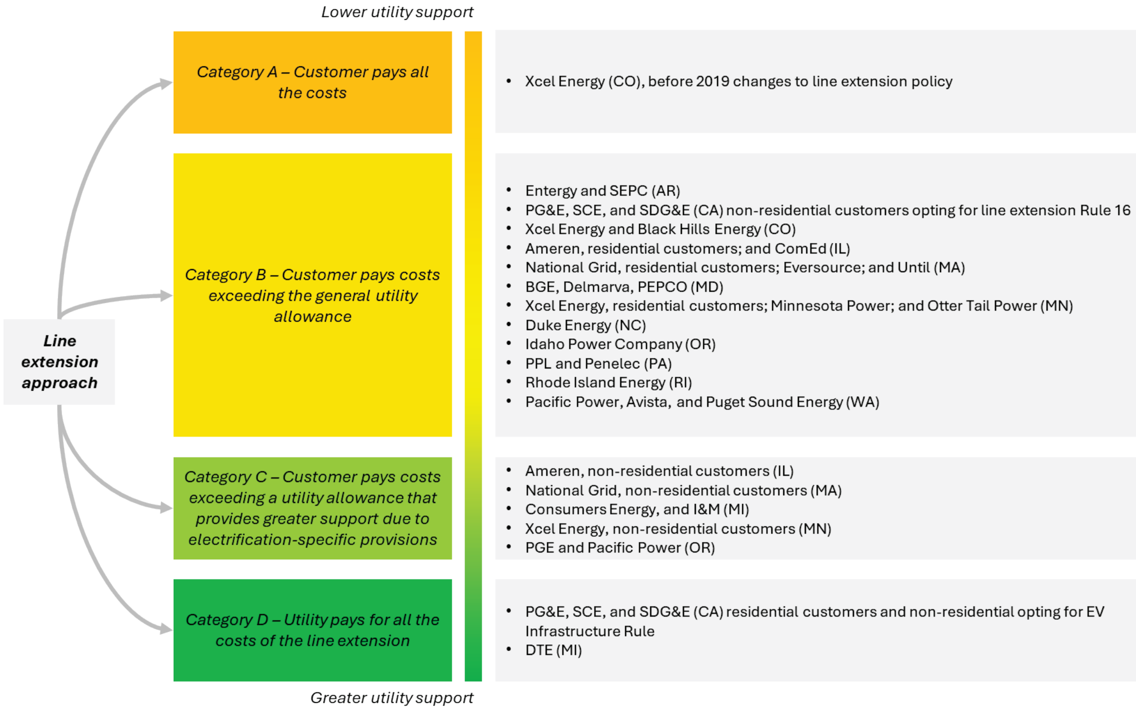


**Figure 3-2. Electrification-related line extension policy categories of support**

Until 2019, this was the case for Colorado's Xcel Energy line extension policy. The line extension policy in place at the time had initially been developed around 40 years prior.[99] To provide an upfront allowance, Xcel Energy required a new customer load requesting to connect to the distribution system to be considered a permanent load. In this case, EV charging was not considered a permanent load.[100] At the time, Xcel Energy considered EV charging stations as an emerging technology, and harder to predict their load.[101] Similarly, albeit outside of the scope of this report, data centers were also not considered a permanent load.[102] In 2019, Xcel Energy changed its line extension policy to consider EV charging a permanent load, recognizing that EV penetration had grown and become more predictable.

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[99] Xcel Energy, 2019, Distribution Line Extension Policy Changes Frequently Asked Questions – Information sheet: Colorado https://www.xcelenergy.com/staticfiles/xe-responsive/Start,%20Stop,%20Transfer/CO_Distribution_Extension_Policy_Changes_FAQ.pdf

[100] The line extension policy stated, *"Regarding Electric Vehicle (EV) Charging stations, beginning with the effective date of this Electric Tariff and ending December 31, 2018, Applicant or Applicants shall be required to pay to Company as a Construction Payment all estimated costs for necessary electric Distribution Main Extension and Service Lateral Extension."* In Xcel Energy's Line Extension Policy in place until 2019, available at https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=884828&p_session_id=

[101] Colorado Energy Office, Xcel Energy, 2019, Answer Testimony and Attachments of G. Christian Williss Attachment GCW-6, available at https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=902903&p_session_id=

[102] Changes to this policy were considered in Docket 18M-0082EG, and the final changes to the line extension policies were approved in Docket 18AL-0852E. Docker 18M-0082EG is available at https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=18M-0082EG, and Docket 18AL-0852E at https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=18AL-0852E

Additionally, Xcel Energy acknowledged that EV loads were materializing in a way that gave the company more confidence in their permanence and growth than in the past.[103]

While this is no longer the practice of Xcel Energy, this example demonstrates how line extension policy designs can create barriers for customers seeking to connect electrification-related loads. Regulators, utilities, and stakeholders in jurisdictions with line extension policies that do not recognize EV charging as a permanent load may wish to consider revising this determination.

### 3.2.2 Category B – Customer pays costs exceeding the general utility allowance

Category B represents the cases when customers have access to an allowance that is available to all customer loads, with no electrification-related considerations. Utilities in this category provide line extension allowances with no differentiation for electrification-related requests. As described, utilities may establish a line extension based on different approaches, such as the costs, distance, assets, or expected revenue. Below, we provide utility examples for each of these approaches.

*Cost of the line extension*

In Minnesota, Minnesota Power provides residential customers with an allowance based on the cost of the line extension. The company will cover up to $751 of the costs for single-phase service for residential customers. For non-residential customers, Minnesota Power covers up to $1,020 for single-phase service and up to $3,152 for three-phase service.[104] Similarly, in Washington, Pacific Power provides residential customers with a $3,150 allowance, above which customers are responsible for any costs associated with the line extension.[105]

*Distance of the line extension*

In Arkansas, Entergy provides residential customers with an allowance based on the distance of the line extension. Entergy will cover the costs of extending the distribution system up to 800 feet of single-phase primary or secondary facilities. For new loads requiring the utility to extend the distribution system beyond 800 feet, the customer is responsible for covering additional costs.[106] In Illinois, Ameren

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103 Colorado Energy Office, 2019, Answer Testimony and Attachments of G. Christian Williss Attachment GCW-7, available at https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=902904&p_session_id=

104 Minnesota Power, 2023, Electric Rate Book, available at https://minnesotapower.blob.core.windows.net/content/Content/Documents/CustomerService/mp-ratebook.pdf

105 Pacific Power Washington, 2023, Rule 14 General Rules And Regulations—Line Extensions, available at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/washington/rules/14_Line_Extensions.pdf

106 Entergy Arkansas, 2022, Rate Schedule No. 60, Extension of Facilities, available at https://cdn.entergy-arkansas.com/userfiles/content/price/tariffs/eal_eofp.pdf?_gl=1*1i5sx6t*_gcl_au*MTk5ODYyMjgzMC4xNzA3MzE2MzI3*_ga*MTEyNDkyNzA1NC4xNzA3MzE2MzI3*_ga_8YKL3FLBBC*MTcwNzMxNjMyNi4xLjEuMTcwNzMxNjM3MS4xNS4wLjA.*_ga_DYMNYBY5CD*MTcwNzMxNjMyNi4xLjEuMTcwNzMxNjM3MS4xNS4wLjA.*_ga_H0JW6TJK3Y*MTcwNzMxNjMyNi4xLjEuMTcwNzMxNjM3MS4wLjAuMA..&_ga=2.122593483.1382662775.1707316327-1124927054.1707316327

provides an allowance for residential customers of up to 250 feet of overhead distribution line extension or 150 feet of underground line extension.[107]

### *Assets needed for the line extension*

In Massachusetts, National Grid provides residential customers with a 150 feet of line extension or one pole, whichever is greater, with customers responsible for any additional assets necessary to serve their load.[108] Rhode Island Energy follows a similar approach to setting its line extension allowance and provides residential customers with an allowance that includes up to two poles and two spans of overhead distribution line to serve customer loads, plus the service drop.[109]

### *Expected revenue to be collected from the load served by the line extension*

In Washington, Puget Sound Energy provides non-residential customers with an allowance based on the expected revenue created by the customer's projected energy usage for one year or based on actual energy usage.[110] Otter Tail Power in Minnesota follows a similar approach and requires customers to contribute to line extension costs when that customer's expected three-year revenue does not justify the utility covering the costs.[111]

## 3.2.3 Category C – Customer pays costs exceeding a utility allowance that provides greater support due to electrification-specific provisions

Category C represents the cases when some electrifying customers have access to a greater allowance than other customers. Most of the practices we identified under this category relate to line extensions for EV charging.

In Illinois, Ameren's non-residential customers opting to receive service under the utility's Optional EV Charging Program are eligible for a supplemental line extension allowance for EV charging.[112] Customers receive an allowance of $300/kW of connected EV-related supply equipment or the standard allowance for new customers, whichever is greater. Ameren's support also includes an equity component. An additional $200/kW will be available for EV charging customers serving low-income communities, for a total of $500/kW. To qualify for this allowance, customers must mainly use the line

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107 Ameren Illinois, 2024, Rider EVCP – Optional Electric Vehicle Charging Program, available at https://www.ameren.com/-/media/rates/files/illinois/aiel4otsq.ashx at 14
108 National Grid, 2024, Terms And Conditions For Distribution Service, available at https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/dist_tcs.pdf at 14
109 Rhode Island Energy, 2020, Terms And Conditions For Distribution Service Appendix A, available at https://www.rienergy.com/site/-/media/rie-jss-app/home/ways-to-save/rates-and-shopping/service-rates/residential-rates/tariff-provisions/tariff-provisions/neco-tcs-policy-1_ripuc_2243.ashx
110 Puget Sound Energy, 2018, Schedule 85 Line Extensions and Service Lines, available at https://www.google.com/url?q=https://www.pse.com/-/media/Project/PSE/Portal/Rate-documents/Electric/elec_sch_085.pdf?rev%3D4e6efd53e5324ac995bbec27fe25cde7%26sc_lang%3Den&sa=D&source=docs&ust=1729879480848402&usg=AOvVaw1IOU8aqpLpm_rMpkSPwzKW
111 Otter Tail Power, 2024, Tariff Schedules, available at https://www.otpco.com/media/bi2fsq50/mn_indexandgeneralrulesandregulations.pdf
112 Ameren Illinois, 2024, Rider EVCP – Optional Electric Vehicle Charging Program, available at https://www.ameren.com/-/media/rates/files/illinois/aiel21rdevcp.ashx

extension for EV charging, with up to 10% usage for non-EV charging. Customers are still responsible for any costs exceeding Ameren's allowance. However, Ameren's policy allows customers to use excess line extension allowance to cover behind-the-meter make-ready infrastructure costs (see Section 2 for a definition) when the line extension costs are lower than the utility's allowance.[113]

In Oregon, Portland General Electric does not consider transformer additions or replacements needed to serve EV charging load as part of the line extension for residential customers.[114] As a result, the total line extension cost will be lower for projects that require transformer upgrades. The transformer costs are recovered from PGE's rate base per its cost allocation rules (see Section 2.3.2 for related discussion). Currently, the line extension allowances available to residential customers are $2,260/dwelling unit for residential service all-electric and $1,590/dwelling unit for residential service where heating is provided by heating fuels (e.g., natural gas, oil, etc.).[115]

Also, in Oregon, Pacific Power's non-residential customers requesting a line extension that will be used predominantly for electric transportation charging infrastructure are eligible for an allowance based on two times the projected annual revenue the customer is expected to generate for the utility. This allowance is greater than that provided to other non-residential, non-electrification line extensions, which are eligible for an allowance based on one year of projected annual revenue.[116]

In Massachusetts, National Grid customers requiring over 25 KVA of transformer capacity are subject to a monthly bill transformer surcharge based on each additional KVA needed. However, this surcharge is

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[113] Ameren Illinois, 2024, Rider EVCP – Optional Electric Vehicle Charging Program, available at https://www.ameren.com/-/media/rates/files/illinois/aiel21rdevcp.ashx at 10

[114] Portland General Electric, 2024, Rule I – Line Extensions, available at https://assets.ctfassets.net/416ywc1laqmd/6O5exEiUrGrN3R4KugNpgy/05b1b919a7f6bddca0dcea824245c81f/Rule_I.pdf at 2https://assets.ctfassets.net/416ywc1laqmd/6O5exEiUrGrN3R4KugNpgy/05b1b919a7f6bddca0dcea824245c81f/Rule_I.pdf at 2. Transformers in residential areas often serve multiple customers, which may be part of the rationale for this and similar line extension policy exclusions.

[115] Portland General Electric, 2024, Schedule 300 Charges As Defined By The Rules And Regulations And Miscellaneous Charges, available at https://assets.ctfassets.net/416ywc1laqmd/Z9SW1311yNz1OUSoi0Syr/a713a8881b64dad2306b9e883dc53378/Sched_300.pdf at 5

[116] Pacific Power, 2024, Rule 13 General Rules And Regulations Line Extensions, available at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/rules/13_Line_Extensions.pdf

waived for customers with separately metered electric vehicle charging infrastructure for customers participating in National Grid's electric vehicle programs.[117]

In Michigan, Consumers Energy's line extension policy indicates they may waive contributions in aid of construction for EV charging-related requests.[118] Also in Michigan, Indiana Michigan Power's line extension policy may cover some of the costs for overhead and underground line extensions for EV charging for customers receiving standard electric service from the utility.[119] Customers receiving only distribution services from the utility may also receive an allowance of up to five times the projected revenue to cover costs related to the overhead and underground line extension for EV charging.[120] The support provided by both utilities is temporary, limited by the duration and budget of the utility EV programs through which these line extension modifications were introduced (i.e., Consumers Energy PowerMIDrive Pilot Program, and Indiana Michigan Power IM Plugged In Pilot Program).

In Minnesota, Xcel Energy's Multi-Dwelling Unit Electric Vehicle Service Pilot Program provides EV charging in affordable housing multi-unit dwellings. Customers enrolled in this program have their line extension costs fully waived.[121] For market-rate housing, support is structured in three tranches with decreasing levels of utility support for line extension costs. Each tranche will have a set budget, and participation will be organized through a competitive process with applications open until funds for

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[117] National Grid, in its tariff for small commercial and industrial retail delivery service, indicates, *"[…] if the KVA transformer capacity needed to serve a customer exceeds 25 KVA, the minimum charge will be increased for each KVA in excess of 25 KVA. This minimum charge will not apply to separately metered Electric Vehicle charging for Customers who participated in one of the Company's Electric Vehicle Programs pursuant to its Electric Vehicle Program Provision, M.D.P.U. No. 1470, as may be amended from time to time."* Available at https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/meco_g1.pdf. The cost of the meter is covered by the company. See National Grid, 2024, Terms And Conditions For Distribution Service, available at https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/dist_tcs.pdf
This is an example of a modification impacting the customer cost of serving new load that did not require a change in the line extension policy and was implemented by a change in the tariff for the small C&I customer class.

[118] Consumers Energy, 2024, Electric Rate Book, available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/consumers/Consumers_14_current.pdf?rev=8b293e175d9a4828bd86ec2d5603a881&hash=ACC024D38FAC872DE47F60C77EFDE60B at 68

[119] The utility will not cover non-standard costs, including directional boring, push boring, hand digging, and placing conduit. Indiana Michigan Power, 2024, Electric Rate Book, available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/indiana-michigan/IM-18-current.pdf?rev=13c3748bf1cf432c972e063f4c726af3&hash=953CF873ECC337DC33FDA7D5313F8509 at 43

[120] Similarly, in this case the utility will not cover costs related to directional boring, push boring, hand digging, and placing conduit. Indiana Michigan Power, 2024, Electric Rate Book, available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/indiana-michigan/IM-18-current.pdf?rev=13c3748bf1cf432c972e063f4c726af3&hash=953CF873ECC337DC33FDA7D5313F8509 at 212

[121] Xcel Energy may refuse service for customers that require excessive capital expenditures. See Xcel Energy Minnesota, 2024, Electric Rate Book, available at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Me_Section_5.pdf at 86 and 90

each tranche are exhausted (Figure 3-3)[122] Site hosts participating in the first tranche will have their line extension costs fully waived. Site hosts in the second and third tranches will receive support for line extension costs based on revenue created through their service extension. Additionally, customers participating in Xcel Energy's EV fleets[123] and EV public charging[124] pilots will not be responsible for line extension costs. This support is limited by the duration of the approved pilot through which these line extension modifications were introduced.

- TRANCHE 1: Full utility support
  - Pilot covers EV service connection costs
  - Pilot covers EV supply infrastructure costs
- TRANCHE 2: Partial utility support
  - Revenue-based allowance for EV service connection
  - Pilot covers a portion of EV supply infrastructure costs
- TRANCHE 3: Limited utility support
  - Revenue-based allowance for EV service connection
  - Little to no EV supply infrastructure support

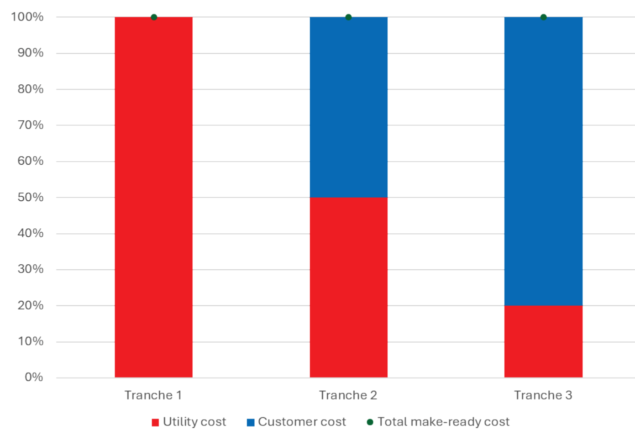


**Figure 3-3. Xcel Energy infrastructure support for the Multi-Dwelling Unit Electric Vehicle Service Pilot Program participants**

Source: Adapted from Xcel Energy[125]

State electrification goals can also shape utility allowance availability. For instance, utility support may be conditional on the fuel mix of the building requesting electric service. See Text Box 3-2 for a description of California's decision to eliminate electric line extension allowance for mixed-fuel new construction.

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[122] Xcel Energy Minnesota, 2020, Docket 20-711, Application Multi-Dwelling Unit Electric Vehicle Service Pilot Program. available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={70A87A74-0000-C610-B151-E024905E5BD5}&documentTitle=20209-166519-01 at 21

[123] Xcel Energy Minnesota, 2024, Electric Rate Book, available at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Me_Section_5.pdf at 86

[124] Xcel Energy Minnesota, 2024, Electric Rate Book, available at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Me_Section_5.pdf at 90

[125] Xcel Energy Minnesota, 2020, Docket 20-711, Application Multi-Dwelling Unit Electric Vehicle Service Pilot Program. available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={70A87A74-0000-C610-B151-E024905E5BD5}&documentTitle=20209-166519-01 at 90

**Text Box 3-2. California's Elimination of electric line extension allowance in mixed-fuel new construction**

| |
|---|
| Starting January 1st, 2025, mixed-fuel new construction projects will no longer be eligible for an electric line extension allowance following a 2023 California Public Utility Commission. Mixed-fuel new construction are buildings that have never been used for any purpose and that use gas or propane in addition to electricity,[126] [127] [128] The Commission decided that providing line extension allowances for mixed-fuel new construction is a barrier to California's strategy to promote all-electric new construction. |

### 3.2.4 Category D – Utility pays for all the costs of the line extension

In California, utilities PG&E, SCE, and SDG&E pay for all the line extension costs associated with EV charging for residential customers and for non-residential customers opting to pursue a line extension through the utilities' EV Infrastructure Rule. For residential customers requiring a line extension for EV charging, the utility will cover any costs in excess of the utilities' standard allowances to support basic charging[129] intended for Level 1 or 2 charging.[130] [131] This support is permanent and utilities are allowed to consider these costs common facility costs to be recovered from all residential ratepayers instead of the individual customer requesting the extension.[132] [133] Non-residential customers installing separately metered EV charger infrastructure may also, at their option, obtain their service line extension through

[126] CPUC, 2023, Decision 23-12-037 Decision Eliminating Electric Line Extension Subsidies For Mixed-Fuel New Construction And Setting Reporting Requirements, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K890/521890476.PDF

[127] Gas line extension allowances were previously disallowed for most new construction in California. See CPUC, 2023, Rulemaking 19-01-011, Decision Eliminating Electric Line Extension Subsidies for Mixed-Fuel New Construction And Setting Reporting Requirements, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K890/521890476.PDF

[128] CPUC, 2023, Decision 23-12-037 Decision Eliminating Electric Line Extension Subsidies For Mixed-Fuel New Construction And Setting Reporting Requirements, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K890/521890476.PDF

[129] California, 2020, Assembly Bill 841, Energy: transportation electrification: energy efficiency programs: School Energy Efficiency Stimulus Program, available at https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB841

[130] California, 2020, Assembly Bill 841, Energy: transportation electrification: energy efficiency programs: School Energy Efficiency Stimulus Program, available at https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB841

[131] CPUC, 2011, Decision 11-07-029 Phase 2 decision establishing policies to overcome barriers to electric vehicle deployment and complying with public utilities code section 740.2, available at https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/139969.PDF

[132] California PUC, 2011, Decision 11-07-029, Phase 2 Decision Establishing Policies to Overcome Barriers To Electric Vehicle Deployment And Complying With Public Utilities Code Section 740.2, available at https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/139969.PDF at 62

[133] PGE's line extension policy, available at https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_15.pdf at 8 and https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_16.pdf at 20; SCE's line extension policy, available at https://edisonintl.sharepoint.com/teams/Public/TM2/Shared%20Documents/Public/Regulatory/Tariff-SCE%20Tariff%20Books/Electric/Rules/ELECTRIC_RULES_15.pdf?CT=1722521909176&OR=ItemsView at 7; SDG&E line extension policy, available at https://tariff.sdge.com/tm2/pdf/tariffs/ELEC_ELEC-RULES_ERULE15.pdf

the EV Infrastructure Rule.[134] [135] For these customers, the utility will cover the full costs of the infrastructure.[136] In this case, customers are required to enroll in a TOU rate to encourage customer charging behavior that reduces electric consumption during periods of peak demand. Additionally, the utilities are required to use existing electric service when possible and cost-effective, aiming to reduce ratepayer costs. However, the Commission recognized that, in some cases, a new service connection may be necessary.[137] This is an alternative to the utilities' Service Line Extension Policy (Rule 16), which provides a line extension allowance with no special EV support, similar to other utility policies described above in Category B. However, non-residential customers opting to be connected through the EV Infrastructure rule cannot design their own facilities as that role is taken by the utility. When designing their facilities, customers must use a qualified contractor who follows the utility's design and construction standards. Customers interested in designing their facilities must pursue their service connection through Rule 16.[138]

In Michigan, DTE will waive the contributions in aid of construction that a customer would be required to pay for line extension requests related to DCFC, Level 2 charging, and fleet charging stations.[139] The support is limited by the duration and budget of DTE's Charging Forward Program, which introduced this line extension modification.

## 3.3 Considerations for line extension policy reforms to enable efficient electrification

Many of the states listed in Category C and D above have existing policies and targets to advance electrification. For example, in 2021, Illinois passed the Climate and Equitable Jobs Act[140] with a goal of adopting one million EVs in Illinois by 2030. Similarly, in 2022, Michigan released the MI Future Mobility

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134 CPUC, 2021, Resolution E-5167 Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric request approval to establish new Electric Vehicle (EV) Infrastructure Rules and associated Memorandum Accounts, pursuant to Assembly Bill 841, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M413/K566/413566906.PDF

135 The EV infrastructure rule is Rule 29 for PG&E and SCE, and Rule 45 for SDG&E.

136 As part of these rules, utilities are required to educate and offer options to customers related to load management.

137 Utilities are required to educate and offer options to customers related to load management. See CPUC, 2021, Resolution E-5167 Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric request approval to establish new Electric Vehicle (EV) Infrastructure Rules and associated Memorandum Accounts, pursuant to Assembly Bill 841, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M413/K566/413566906.PDF

138 PGE's EV Infrastructure Rule, available at https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_29.pdf; SCE EV Infrastructure Rule, available at https://edisonintl.sharepoint.com/teams/Public/TM2/Shared%20Documents/Public/Regulatory/Tariff-SCE%20Tariff%20Books/Electric/Rules/ELECTRIC_RULES_29.pdf?CT=1730133081658&OR=ItemsView; SDG&E EV Infrastructure Rule, available at https://tariff.sdge.com/tm2/pdf/tariffs/ELEC_ELEC-RULES_ERULE_45.pdf

139 DTE, 2024, Rate Book for Electric Service, Distribution Systems, Line Extensions And Service Connections, available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/dte/dtee1cura1throughc.pdf?rev=92d45ef14fba4f8f97ec562d01265991&hash=32CA07432073654D52209677C294A250 at 70

140 State of Illinois, 2021, Climate and Equitable Jobs Act (CEJA), Public Act 102-0662, available at https://epa.illinois.gov/content/dam/soi/en/web/epa/topics/ceja/documents/102-0662.pdf

Plan, aiming to deploy 100,000 electric vehicle chargers to support two million EVs by 2030.[141] These policy mandates may motivate states to take additional actions to enable electrification, such as actions to ensure line extension policies align with electrification goals. State policymakers and regulators can consider revising line extension policies in a number of ways to support electrification. Below, we describe relevant considerations identified through our review of state practices.

### 3.3.1 Line extension dimensions

Line extension policies can be structured to address different dimensions, which impact the utilities' and customers' roles and responsibilities for serving electrification-related loads and associated costs. Table 3-2 describes dimensions states may consider and provides examples of utility practices.

**Table 3-2 Line extension dimensions**

| Dimension | Summary |
|---|---|
| **Allowance amount available** | States may consider the extent to which existing line extension allowances adequately reflect future expected benefits from serving new loads due to electrification. States may increase the allowance or change the method to calculate the allowance provided to electrification-related line extension requests. (See Oregon's Pacific Power example in Section 3.2, Category C). |
| **Allowance asset scope** | States may consider redefining the scope of the assets covered by a line extension policy. States can consider restricting or expanding the assets that the line extension allowance is set to cover. Additionally, states may consider letting the line extension allowance be used to cover behind-the-meter costs (See Illinois's Ameren example in Section 3.2, Category C). |
| **Duration of changes** | States may consider existing policy goals and electrification trends to understand the impact of changes to line extension policies and determine the most appropriate duration for policy changes. States may pursue temporary changes for a specific time or tied to a budget limit (See Michigan's Consumers Energy example in Section 3.2, Category C). Alternatively, states may implement permanent changes to accommodate significant market development, such as growth in EV adoption (See California's examples in Category D). |
| **Infrastructure utilization** | States may consider introducing customer eligibility criteria for electrification-specific line extension policies. For example, this may include separate metering for the assets served under the line extension or requiring the line extension to be predominantly used to serve electrification end uses. (See Oregon's Pacific Power example in Category C).[142] |
| **Customer segments** | States can consider the needs of residential and non-residential customers separately and implement line extension policy reforms that address specific customer segment needs. (See California's examples in Category D). |
| **Equity** | States may consider advancing equity goals through line extension policies as part of their reforms to support electrification. Equity-focused action may include greater support for infrastructure serving income-eligible customers, affordable housing, or environmental justice communities. (See Minnesota's Xcel Energy example in Category C). |

[141] Michigan Office of Future Mobility and Electrification, 2022, MI Future Mobility Plan, available at https://www.michiganbusiness.org/4aecec/globalassets/documents/mobility/state-strategy-for-the-future-of-mobility-and-electrification-detailed-version.pdf

[142] Relatedly, in Section 2.2.4., we describe utility electrification program characteristics related to infrastructure utilization, such as including requirements for customer enrollment in TOU rates or load management measures.

### 3.3.2 Future-oriented considerations

Line extension policies may also be structured to consider future loads. Below, we describe how utilities may consider future proofing, as well as the use of refunds to recognize the benefits of new line extensions in enabling future loads to connect.

*Future-proofing line extension infrastructure*

States may consider a proactive approach to line extension asset deployment that allows utilities to future-proof the extension to include additional capacity to meet future load growth needs. A proactive approach for line extensions may be more cost-effective as it could reduce the need for future project planning, permitting, and labor costs, which will tend to be higher for multiple sequential projects than for one integrated upgrade. However, this approach must also consider mechanisms to ensure proactive investments are deployed based on reasonable certainty that load growth will materialize. In California, utilities PG&E, SCE, and SDG&E received Commission approval to future-proof line extensions deployed through the utilities' EV infrastructure rules for non-residential customers (see Section 3.2.4, Category D). When utilities propose future-proofing of line extensions, the Commission requires them to obtain a signed commitment from customers to confirm their intention to install future EV charging infrastructure, including the timing for the installation and the number of chargers they plan to install.[143] Section 4 discusses proactive investment approaches for assets further upstream in the distribution system.

*Cost refund approaches*

States may consider whether existing refund mechanisms in their line extension policies are sufficient to adequately support electrification and ensure fair cost allocation practices for system expansion needed for load growth. Traditional line extension policies generally include a process through which the customer requesting the line extension policy may be eligible for a refund of costs they contributed toward the line extension. A customer may be eligible for a refund if the utility earned more revenue than initially projected when the line extension was deployed.[144] Customers may also be eligible for a refund if their line extension enables future load. For example, a customer may contribute towards the costs of a service upgrade that allow future load from other utility customers to be served. In case the utility would refund the initial customer when new loads are able to connect to the distribution system through the initial customer line extension. For example, Ameren will provide refunds to customers when additional customers connect to the system. In this case, customers are required to notify Ameren when a refund is due and will be eligible for a refund for up to ten years.[145] [146]

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143 CPUC, 2021, Resolution E-5167 Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric request approval to establish new Electric Vehicle (EV) Infrastructure Rules and associated Memorandum Accounts, pursuant to Assembly Bill 841, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M413/K061/413061495.PDF

144 This approach is seen in utilities in California, Colorado, Michigan, Minnesota, Pennsylvania, and Rhode Island.

145 Ameren Illinois, 2024, Expansion and Modification of Electric System, available at https://www.ameren.com/-/media/rates/files/illinois/aiel4otsq.ashx

146 This approach is seen in utilities in California, Colorado, Illinois, Massachusetts, Minnesota, Oregon, Pennsylvania, and Washington.

## 3.4 Pathways for line extension policy reform

Through our review of existing line extension policy practices presented above (Section 3.2), we identified pathways through which states can reform these policies to support electrification-driven load growth. Below, we describe these pathways, including examples of states that have implemented line extension policy changes through them.

### 3.4.1 Executive order pathway

States may issue executive orders to encourage utilities to pursue policies enabling electrification, creating a supportive environment for line extension policy reform.[147] States pursuing this pathway may opt to explicitly identify line extension policy reforms as part of the executive order mandate or may provide general direction or set goals that line extension policies can help achieve. For example, in 2020, Oregon issued Executive Order 20-04, "Directing State Agencies to Take Action to Reduce and Regulate Greenhouse Gas Emissions," directing the Commission to encourage utilities to support transportation electrification infrastructure to provide long-term customer benefits and contribute to state policy goals.[148] To support the executive order's goals, Pacific Power proposed and received regulatory approval to introduce a new line extension policy that doubled the allowance for non-residential customers whose transportation charging demand constitutes at least 80% of their total load.[149]

### 3.4.2 Legislative pathway

States may pass legislation to create opportunities for line extension reform to occur. State legislation on line extension policies may create an opportunity for regulators and stakeholders implementing the law to make line extension reforms that are supportive of cost-effective electrification, even if the legislation itself does not articulate electrification-specific provisions. This was the case in Colorado when the legislature passed SB17-271 in 2017.[150] This bill directed the Public Utility Commission to initiate a proceeding to evaluate existing electric investor-owned utility line extension policies and to propose recommendations for utilities to increase transparency of line extension cost recovery and

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147 State authority to issue executive orders varies. For a detailed list of state authorities regarding executive orders, see The Council of State Governments, 2021, The Book of States, available at https://www.nga.org/wp-content/uploads/2022/10/CSG-book-of-the-states-2021.pdf Table 4.5 at 133
148 Oregon, 2020, Office of the Governor State of Oregon, Executive Order 20-04, available at https://www.oregon.gov/gov/eo/eo_20-04.pdf
149 Oregon PUC, 2020, Pacific Power, Docket No. ADV 1148/Advice No. 20-009, Updates to Rule 13 - Line Extension Allowance for Non-Residential Transportation Electrification Customers. available at https://edocs.puc.state.or.us/efdocs/UBF/adv1148ubf143315.pdf
150 Colorado, 2017, Senate Bill 17-271 Concerning the development of a transparent process by which an investor-owned utility may recover actual costs from a property owner on whose behalf the utility has extended its service by connecting the property owner's property to the utility's service, available at https://leg.colorado.gov/sites/default/files/documents/2017A/bills/2017a_271_enr.pdf

align with industry practices.[151] [152] This proceeding led to a change in Xcel Energy's electric line extension policies to recognize electric vehicle charging as a permanent load and therefore eligible for the line extension allowance (See Section 3.2.1, Category A).

Alternatively, state legislation can specify changes or inquiries into utility line extension policies focusing on electrification. This was the case in Colorado in 2023, SB23-291[153] directed the Commission to conduct a study on existing investor-owned utility tariffs and interconnection policies to determine barriers to the beneficial electrification of buildings and transportation and provide recommendations, including for line extension policies and practices.[154] In California's 2020 Assembly Bill (AB) 841[155], which directed the Commission to allow residential line extensions for EV charging as a common facility cost to be recovered from all ratepayers (See Section 3.2.4, Category D). Similarly, in 2024, Colorado passed SB24-218[156] with a similar goal of requiring utilities to cover the full cost of residential line extensions for electrification and distributed energy resources (DER). Additionally, the bill directed the Commission to consider an optional flexible interconnection[157] tariff to be used as an alternative to infrastructure upgrades necessary for customers requesting to interconnect a DER or energize new load, such as from EV adoption. Xcel Energy plans to submit a flexible interconnection tariff in 2025 for Commission consideration.[158] [159] [160]

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151 Colorado General Assembly, 2017, Investor-owned Utility Cost Recovery Transparency, available at https://leg.colorado.gov/bills/sb17-271

152 Xcel Energy, 2019, Distribution Line Extension Policy Changes Frequently Asked Questions – Information sheet: Colorado https://www.xcelenergy.com/staticfiles/xe-responsive/Start,%20Stop,%20Transfer/CO_Distribution_Extension_Policy_Changes_FAQ.pdf

153 Colorado, 2023, Senate Bill 23-291 Concerning the public utilities commission's regulation of energy utilities, and, in connection therewith, making an appropriation, available at https://leg.colorado.gov/sites/default/files/2023a_291_signed.pdf

154 Colorado PUC, 2023, Docket 23M-0464EG, Impact of investor-owned utilities' tariffs, policies, and practices on beneficial electrification and distributed energy resources, available at https://drive.google.com/file/d/1dxKr9zLfi9mmljLOnOhq4mcSYYK89PqW/view

155 California, 2020, Assembly Bill 841, Energy: transportation electrification: energy efficiency programs: School Energy Efficiency Stimulus Program, available at https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB841

156 Colorado, 2024, Senate Bill 24-218 Concerning measures to modernize energy distribution systems, and in connection therewith, making an appropriation, available at https://leg.colorado.gov/sites/default/files/2024a_218_signed.pdf

157 This bill defines flexible interconnection as "[…] a set of rules and requirements for expeditiously energizing new load or interconnecting a distributed energy resource to a qualifying retail utility's distribution system and includes an agreement for curtailing the import or export of electricity from and to the distribution system". See Colorado, 2024, Senate Bill 24-218 Concerning measures to modernize energy distribution systems, and, in connection therewith, making an appropriation, available at https://leg.colorado.gov/sites/default/files/2024a_218_signed.pdf at 6

158 Xcel Energy, 2024, Distribution System Plan, December 16, 2024, available at https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_fil=G_821326&p_session_id= at 176

159 In 2023, Xcel Energy presented a draft of its flexible interconnection roadmap at a distribution system planning technical working group meeting. See Gridworks, 2023, PSCo DSP Technical Working Group Meeting #2 Flexible Interconnection Demonstrations, available at https://gridworks.org/wp-content/uploads/2024/04/09.28.2023-Slides_-Mtg-2.1_-Flexible-Interconnection_PSCo-DSP-Technical-Working-Group_with-survey-results-1.pdf at 8-15

160 California, New York, Illinois, and Massachusetts have flexible interconnection approaches in place, for more detail, see DOE, 2024, Flexible Distributed Energy Resources Electric Vehicle Connections, available at https://www.energy.gov/sites/default/files/2024-08/Flexible%20DER%20%20EV%20Connections%20July%202024.pdf

### 3.4.3 Regulatory pathway

States may pursue line extension reforms through commission proceedings (e.g., rate cases) and commission decisions, proceedings dedicated to implementing utility programs, or dockets focused on line extension policies. This regulatory pathway is also generally necessary when states pursue the executive order and legislative pathways described above, as those mechanisms typically require the commission to facilitate implementation and provide regulatory oversight. However, some state regulators initiate potential line extension reform in regulatory proceedings without executive or legislative direction to do so. For example, in 2013, the Oregon Commission approved changes to Portland General Electric line extension policy (See Section 3.2.2, Category B) as part of the utility's rate case settlement agreement.[161] Similarly, in Michigan, the Commission approved changes to the line extension policies to provide a greater allowance for EV programs for utilities DTE, Consumers, and Indiana Michigan Power as part of their rate cases (See Section 3.2, Category C and D).

The regulatory pathway can also lead to future legislative action. For example, California's AB 841, discussed above, elevated an existing interim Commission policy—which considers residential line extensions for EV charging as a common facility cost to be recovered from all ratepayers—into the standard policy of the Commission. The interim policy initially applied to investor-owned utilities and was approved by the Commission in 2011,[162] extended in 2013,[163] 2016,[164] and 2019,[165] and expanded to apply to smaller electric utilities in 2016.[166]

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161 Oregon PUC, 2023, Docket UE416, Portland General Electric Request for a General Rate Revision; and 2024 Annual Power Cost Update, available at https://apps.puc.state.or.us/orders/2023ords/23-386.pdf

162 CPUC, 2011, Decision 11-07-029 Phase 2 decision establishing policies to overcome barriers to electric vehicle deployment and complying with public utilities code section 740.2, available at https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/139969.PDF

163 CPUC, 2013, Decision 13-06-014 Decision authorizing short-term extension of limited provisions regarding electric tariff rules 15 and 16, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M070/K281/70281733.PDF

164 CPUC, 2016, Decision 16-06-011 Decision authorizing further extension of the interim policy regarding electric tariff rules 15 and 16, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K212/163212633.PDF

165 CPUC, 2019, Rulemaking 18-12-006 administrative law judges' ruling extending interim policy on common facility costs related to electric rules 15 and 16, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M322/K122/322122150.PDF

166 CPUC, 2016, Decision 16-11-005 Decision making small electrical corporations respondents to this rulemaking, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M169/K717/169717954.PDF

# 4. Emerging practice for recovering and allocating proactive distribution system costs due to electrification

Utilities face significant and uncertain load growth that will require inve3stment in major upstream distribution system assets, including substations and primary distribution lines. Building or upgrading these assets is a time-consuming process. If utilities wait until customer demand requires these upgrades, these long lead times will prevent them from serving the new load for years, slowing growth and deterring customer adoption because of interconnection delays. This conundrum is motivating interest in proactive distribution system investments to ensure the distribution system can serve the growing load (EFI Foundation, 2024; Moran et al., 2023). Investing proactively requires new processes and strategies and an evolution of utility and regulatory distribution system planning and investment practices, which have historically focused on a just-in-time, more reactive investment approach.

In this report, we define distribution system proactive investments as those that are deployed ahead of certain load growth. These may include investments to serve new loads ahead of the utility receiving a load letter, as well as investments deployed to serve expected load growth that do not target an existing system constraint.[167] Proactive investments may also include investments in infrastructure that may not fit existing regulatory practices and planning processes due to their more uncertain forward-looking nature, such as upgrading a feeder or transformer to add capacity beyond near-term needs to be able to accommodate longer-term forecasted load growth from EV fleet adoption.

This section reviews emerging practices for proactive distribution system investments, including risk considerations, state-level actions, legislation and regulatory proceedings, and risk management options that regulators, utilities, and other industry stakeholders may wish to consider as proactive investment practices evolve.

## 4.1 The growing need for proactive investments to enable load growth

A recent report from GridStrategies, based on data from the FERC, demonstrates the expected increase in demand for electricity. In 2022, the five-year forecasted peak demand growth was 23 GW. By 2024, their five-year estimate had risen to 128 GW, increasing about five times. This rapid growth will be driven by data centers, manufacturing, and electrification technology adoption at the grid edge (e.g., adoption of EVs and heat pumps). Electrification is a near-term load growth driver across a number of regions, including CAISO, ISO-NE, MISO, NYISO, and PJM, with more regions expecting significant electrification load growth after 2030 (Wilson et al., 2024). Traditionally, investments in distribution system infrastructure have followed a just-in-time approach, where a decision to invest is responsive to a specific system or customer need, with the expectation that assets deployed will be utilized close to the time they are deployed. Decisions under a just-in-time approach focus on the near future and are generally presented to and approved by regulators in rate case proceedings. This just-in-time approach

[167] Load letters provide utilities with details on the electric load of a building or facility. Utilities use the information provided in load letter to size infrastructure and ensure they can provide reliable electric service.

has been an accepted investment strategy practice in the context of slow or no demand growth (Figure 4-1) (Tsuchida et al., 2024), which supported a more reactive approach to system needs in the past two decades.

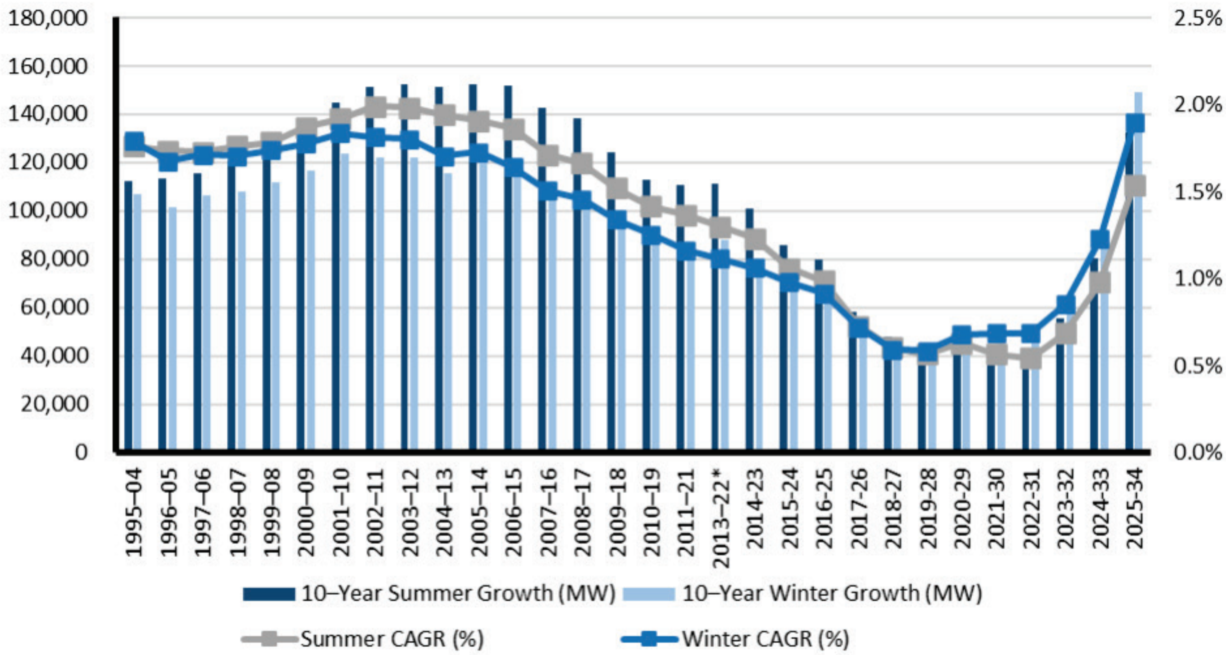


**Figure 4-1. NERC 10-year summer and winter peak demand growth, 1995-2024**

Source: From NERC (2024: p. 31)

Utilities operating under a just-in-time approach may face challenges in providing timely electric service to meet significant load growth, as surging customer load may outpace the utilities' ability to invest in distribution system infrastructure to meet customer needs. For example, a just-in-time approach may lead to significant delays if utilities cannot increase their staffing levels rapidly. Figure 4-2 illustrates National Grid's timeframes to meet electrification load growth-driven distribution system investment needs. In their analysis, National Grid found that to deliver capacity in some areas of the system, planning would have to start now, considering long load times to design and deploy assets (e.g., a substation can take up to eight years to be brought into service). In another example, electric vehicle charging station deployments have been slowed in California due to limited grid capacity, leading to long waiting periods (Conrad et al., 2024). In 2023, representatives from cities, towns, and counties; community choice aggregators; and energy, rural, business, and environmental and climate groups urged California policymakers to address interconnection delays impacting new loads from buildings and transportation (APPA, 2023).

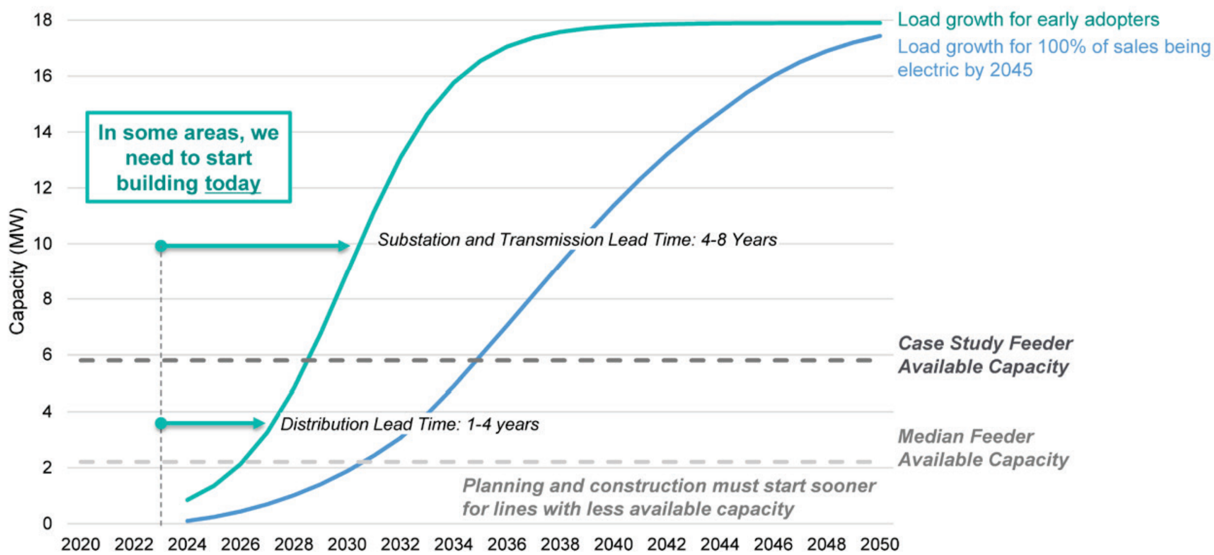


**Figure 4-2. National Grid's infrastructure deployment timelines to meet medium- and heavy-duty electric MHDEV electrification load growth**

Source: From National Grid and Hitachi Energy (2023: p. 6)

In the United States, emerging state legislation and regulatory proceedings are working towards processes to enable more proactive distribution system investments. We provide an overview of state-level actions identified through our research in this section. Beyond the United States, in 2023, the European Commission released an action plan focused on electricity grids, including transmission and distribution, recognizing the importance of proactive investments (here called "anticipatory" investments) in enabling electrification and clean energy. The action plan also recognizes the need for guiding principles to support decision-making on proactive investments (European Commission, 2023).

Decisions to deploy distribution system assets proactively are likely to be made under greater uncertainty on when they will be needed, where they will be needed in the system and the scale of those needs (EPRI, 2024a). The degree of uncertainty facing proactive investments will likely depend on the driver for load growth and the location where assets are deployed. For example, in dense urban areas, there may be more confidence that the load for EV charging will likely increase in highway service plazas. In this case the location uncertainty is reduced as vehicle flow patterns are unlikely to change drastically rapidly.

Proactive investments and planning approaches in the electric system have been followed for other use cases. For example, at the transmission level, MISO has facilitated the deployment of significant investments to enable the interconnection of renewable energy (RE) generation.[168] This proactive planning and investment approach considers a 20-year long-range planning horizon. The process aims to deliver transmission infrastructure to address changing state policies on their resource mix,

[168] MISO, 2024, Multi-Value Projects (MVPs), available at [https://www.misoenergy.org/planning/multi-value-projects-mvps/#t=10&p=0&s=Updated&sd=desc](https://www.misoenergy.org/planning/multi-value-projects-mvps/#t=10&p=0&s=Updated&sd=desc)

increasingly including clean energy mandates and the growth in interconnection requests, predominantly from renewable sources. In 2011, MISO approved a ~$6 billion portfolio of projects (MISO, 2025), [169] and in 2022, a ~$10 billion portfolio (MISO, 2021). This proactive approach to transmission planning contrasts with the more traditional piecemeal approach under which 90% of U.S. transmission investments have been justified, focusing on near-term local or regional reliability criteria (Pfeifenberger, 2023).

Similarly, in Texas, a 2005 law required the Commission to lead a process to identify Competitive Renewable Energy Zones (CREZ), defined as areas with significant RE potential, land availability, and feasible transmission routes (Cohn & Jankovska, 2020), and proactively build transmission infrastructure to enable renewable generation. The process to identify these areas concluded in 2007 with five CREZ selected. Texas utilities completed the deployment of transmission lines in 2014, totaling ~3,600 miles of 345 kV circuits to serve ~18.5 GW, with a total cost of $6.9 billion (ERCOT, 2014).

In 2022, Massachusetts regulators approved a Provisional System Planning Program to enable utilities to proactively invest in system upgrades to ensure adequate capacity to interconnect distributed generation and other DER (Valova & Brown, 2022). This program was the result of a Commission investigation into DER planning improvements to facilitate state goals of net-zero greenhouse gas emissions, including the Massachusetts 2050 Decarbonization Roadmap and the Act Creating a Next Generation Roadmap for Massachusetts Climate Policy.[170] Under this program, Massachusetts utilities can propose capital investment projects for regulatory approval to support the timely and cost-effective interconnection of future distributed generation.[171] Text Box 4-1 provides insight into the types of investments supported through this program for Eversource. In Minnesota, Xcel Energy recently received regulatory approval for ~$10 million in proactive hosting capacity upgrades affecting four substations.[172] [173] [174]

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169 MISO's transmission projects are designed to meet one or more of the following goals: enable regional public policy needs and provide regional reliability and economic value. See MISO, Multi-Value Projects, available at https://www.misoenergy.org/planning/multi-value-projects-mvps/#t=10&p=0&s=Updated&sd=desc

170 MA DPU, 2020, D.P.U. 20-75-B, Investigation by the Department of Public Utilities on its Own Motion into Electric Distribution Companies' (1) Distributed Energy Resource Planning and (2) Assignment and Recovery of Costs for the Interconnection of Distributed Generation, Order on Provisional System Planning Program, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14232299

171 MA, 2022, Provisional System Planning Summary, available at https://www.mass.gov/doc/provisional-system-planning-summary-0/download

172 MN PUC, 2023, E002/M-23-452, Transportation Electrification Plan 2023 Integrated Distribution Plan Xcel, available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={B07D8C8B-0000-C521-A8F5-FE267238317D}&documentTitle=202311-200132-10 at 128

173 MN DOC, 2024, Docket 23-458, In the Matter of Xcel Energy's Renewable Development Fund for Distributed Energy Resources System Upgrade Program Proposal, available at https://www.edockets.state.mn.us/documents/%7B80429B8E-0000-C117-B25E-DF537BCC2DD9%7D/download?contentSequence=0&rowIndex=5

174 Xcel Energy, 2023, Docket 23-458, Proposed Program Plan, In the Matter of Xcel Energy's Renewable Development Fund for Distributed Energy Resources System Upgrade Program Proposal, available at https://www.edockets.state.mn.us/documents/%7B30608C8B-0000-CA19-9137-DCB9ABD9D3C4%7D/download?contentSequence=0&rowIndex=13

**Text Box 4-1. Eversource's distributed generation proactive distribution system upgrades**

In 2024, Eversource received regulatory approval for proactive distribution system upgrades that added more system capacity than immediately needed, thereby enabling future distributed generation to interconnect.[175] For example, one of the approved distribution system upgrades located in Plymouth included:[176]

- Upgrading five existing transformers across four substations
- Adding a new transformer, switchgear, and duct bank gateway cable at two substations
- Upgrading of overhead and underground distribution lines
- Adding 20 new distribution feeders across four substations

These upgrades will enable 117 MW of distributed generation already in the queue to interconnect and enable an additional 262 MW of capacity for future distributed generation interconnection not yet in the queue.[177] The estimated cost for these upgrades is $152.2 million, of which $81.7 million is for substation costs and $70.5 for distribution line costs.[178]

System upgrades implemented through the Provisional System Planning Program are initially funded by ratepayers. Those ratepayers are later reimbursed over time as distributed generation projects connect to the system. These projects will pay connection fees determined by the share of the upgrade costs necessary to serve a distributed generation project. This cost allocation and recovery approach reduced the burden on initial distributed generation projects. The Commission found that the traditional approach, which would have required the first batch of projects to pay the full cost of any upgrades needed to interconnect,[179] would be a barrier to short-term distributed generation deployment and to meeting state policies related to greenhouse gas emissions and clean energy.[180] Note that this approach is similar to that taken by certain refundable line extension policies (see Section 3.3.2).

[175] MA DPU, 2024, Order by Chair Van Nostrand, Commissioners Fraser and Rubin. D.P.U. 22-52/22-53/22-54/22-55, available at https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber/22-54

[176] MA DPU, 2024, Order by Chair Van Nostrand, Commissioners Fraser and Rubin. D.P.U. 22-52/22-53/22-54/22-55, available at https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber/22-54 at 28

[177] Eversource, 2024, Provisional System Planning Tariff, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/19496841

[178] MA DPU, 2024, Order by Chair Van Nostrand, Commissioners Fraser and Rubin. D.P.U. 22-52/22-53/22-54/22-55, available at https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber/22-54

[179] MA DPU, Provisional System Planning Program Summary, available at https://www.mass.gov/doc/provisional-system-planning-summary-0/download

[180] MA DPU, 2020, D.P.U. 20-75-B, Investigation by the Department of Public Utilities on its Own Motion into Electric Distribution Companies' (1) Distributed Energy Resource Planning and (2) Assignment and Recovery of Costs for the Interconnection of Distributed Generation, Order on Provisional System Planning Program, available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14232299

## 4.2 Risk considerations pertaining to just-in-time and proactive investments

Continuing the practice of just-in-time distribution system investments carries risks to utilities, ratepayers, and potential technology adopters in the context of significant load growth. Similarly, pursuing proactive distribution system investments to enable new loads from EVs and heat pump technology adoption carries associated risks. This section describes the risks associated with both just-in-time and proactive investments. The risks presented below may be interrelated and not mutually exclusive. Regulators and utilities may consider these risks as they weigh whether and how to implement processes to identify and approve proactive investments. In this section, we identify risks; in Section 4.4 we discuss ways that utilities and regulators can mitigate them.

### 4.2.1 Risks of investing just-in-time

*Delayed energization risk*

Investing just-in-time may prevent customers from electrifying their end-uses, result in a significant delay in connecting to the system or upgrading service, and ultimately negatively impact customers' experiences and ability to adopt new technologies (Palmintier et al., 2023). The risk of delayed energization can impact residential customers seeking to adopt EVs and heat pumps, as well as C&I customers who may be unable to meet their sustainability targets and/or comply with state policy on EVs (EDF, 2024). Delayed energization may impact affordability in cases where technology adoption was motivated by the potential for bill savings. Beyond the direct impact on customers, barriers and delays to connecting to the distribution system may hinder demand for EVs and heat pumps, impacting market growth. Delayed energization may also impact economic development (for example, delayed energization for a new EV fleet location may delay the inflow of economic activity to surrounding businesses).

*Revenue loss or delay risk*

Investing too late can result in a loss or delay in new utility revenue from serving load growth (Brattle Group, 2021). This risk can delay or prevent customers from benefiting from the potential for downward pressure on rates that may result from greater electricity sales.

*Fossil fuel technology lock-in risk*

Customers facing barriers to adopting EV and heat pump technologies may continue using technologies reliant on fossil fuels for longer, which could have otherwise been replaced with electric technologies. For instance, customers facing challenges connecting EV charging to the distribution system may opt to continue using an internal combustion engine vehicle for longer or purchase a new internal combustion engine vehicle instead of their preferred EV. Similarly, customers may opt to continue using existing gas or oil furnaces for longer or replace them with new ones that will be in use for decades, instead of considering heat pump options.

*Public policy goal risk*

Investing just-in-time may hinder local, state, or federal policy goals. Public policy goals may include climate and energy policies with decarbonization targets, which would be hindered by a distribution system that delays or prevents EV and heat pump technology adoption (Morash et al., 2024). Policy goals may also include improving public health. Delays in the adoption of EV and heat pumps may lead to greater exposure to high-emissions transportation and heating.

*Unsuitable investment risk*

In this case, investing just-in-time may result in a need to select investments under pressure to serve immediate demand, which may limit opportunities to plan for current and future needs and expected load growth. This could result in a series of sequential investments, which might carry greater costs than an integrated proactive investment approach that considers longer-term needs. Sequential investments might duplicate efforts, such as the time, budget, and staff necessary for planning, designing, and constructing distribution system assets as well as the distribution system assets themselves.

### 4.2.2 Risks of investing proactively

*Stranded asset risk*

Proactive distribution system investments may result in stranded assets when the actual load growth is significantly lower than the load growth potential initially identified at the time when the investment was made. Similarly, an investment may lead to a stranded asset if the location of the actual load demand differs from the location where the proactive investment was deployed. For example, this could occur where residential adoption of EVs and heat pumps differs in the location where load growth was expected in the forecasts (Klock-McCook et al., 2024). This could also happen in cases where utilities pursue proactive investments to support large, localized loads, such as a fleet, but those loads end up not materializing. Stranded assets from proactive investments can lead to upward pressure on rates, given that the underutilized assets would support less electricity sales than initially forecasted when the investment was made and result in less utility revenue than the initial investment cost.

*Unsuitable investment risk*

This is a parallel to the unsuitable investment risk associated with just-in-time investments, described above. Proactive distribution system investments are more dependent on future projections. Uncertainty in those projections in combination with the potential for utility capital bias can contribute to unsuitable investment risk. This may result in deploying assets that are not the best option to serve load growth as it actually occurs. For instance, suppose that a utility installs new transformers and other distribution system assets to accommodate anticipated demand growth. Yet, given the nature of the actual demand growth when it arrives, a more cost-effective NWA could have been deployed to defer some of those investments while addressing the same system needs (EPRI, 2024a). Proactive investments may limit such future options by locking in decisions. Moreover, they also raise the chances of making a suboptimal investment, since utilities will not know the full details of the future demand to be served.

### *Inappropriate cost allocation risk*

Proactive investments may carry cost allocation risk if they result in an inequitable distribution of costs across ratepayers, since the cost allocation approach must be established before it is clear who the beneficiaries of the proactive investments are. For example, a proactive investment to enable EV fleets may also enable commercial and residential customers in the area to add new loads. Similarly, load growth may materialize to forecasted levels but be driven by different customer classes than initially considered when designing cost allocation mechanisms. If the cost of the investment were allocated solely to the fleet, this allocation would not meet the costs follow benefits principle for cost allocation (i.e., which customers benefit from the investments) and could be deemed inequitable) (Lazar et al., 2020). Mechanisms that allow for cost allocation adjustments after the fact may be very helpful to manage this risk (see Text Box 4-1).

The risks of investing just-in-time or proactively impact different stakeholders. Table 4-1 illustrates how the risks described above may vary in terms of impacts to key stakeholders, including utility ratepayers, customers adopting technologies leading to load growth, utility shareholders, and all of society. The table aims to illustrate the relationship between potential risks and stakeholders. The table does not characterize the magnitude of the risk for risks affecting multiple stakeholders, and we recognize that risks may not be equally distributed.

**Table 4-1. Impact of just-in-time and proactive investments across stakeholders**

| | Risk to stakeholders | | | |
|---|---|---|---|---|
| | **Ratepayers (all customers)** | **Adopting customer (individual)** | **Utility shareholders** | **Society (Public policy)** |
| ***Risks of investing just-in-time*** | | | | |
| ***Delayed energization risk*** | | ✓ | | ✓ |
| ***Revenue loss or delay risk*** | ✓ | | ✓ | |
| ***Fossil fuel technology lock-in risk*** | | ✓ | | ✓ |
| ***Public policy goal risk*** | | | | ✓ |
| ***Unsuitable investment risk*** | ✓ | | ✓ | |
| ***Risks of investing proactively*** | | | | |
| ***Stranded asset risk*** | ✓ | | ✓ | |
| ***Unsuitable investment risk*** | ✓ | | ✓ | |
| ***Inappropriate cost allocation risk*** | ✓ | ✓ | | |

## 4.3 Emerging state policy landscape

Recognizing the need for proactive distribution system investments, a growing number of states are taking legislative and regulatory actions to enable load growth from EV and heat pump technologies. Through our review, we identified legislative actions related to proactive investments in California, Colorado, and Massachusetts. Additionally, we identified regulatory actions in California, Colorado, Massachusetts, Minnesota, North Carolina, and New York (Table 4-2). This section describes the main characteristics of the legislative and regulatory actions identified, including details on cost recovery and allocation when applicable.

The legislative and regulatory actions reviewed in this section provide insights on states across different stages in the process to enable proactive investments. Some states have passed legislation that recognizes distribution system capacity constraints and the need for proactive investments (California, Colorado, and Massachusetts). Colorado conducted a study to understand existing distribution system barriers to transportation and building load growth and identify priority areas of improvement. Other states are establishing working groups, processes, and frameworks through which proactive investments will be considered (California, Minnesota, and New York). In other cases, states have issued orders (Colorado, Massachusetts, Minnesota, and North Carolina) or ongoing proceedings (California) considering proactive investment plans and proposals. In general, these states are still in the emerging phase of establishing proactive investment strategies and are defining goals, articulating principles, and creating processes.

### 4.3.1 California

*Legislative action*

***AB 2700 – Transportation electrification: electrical distribution grid upgrades***[181]

Passed in 2022, this legislation focused on transportation electrification. It established that utilities must be able to proactively plan and build distribution grid upgrades to accommodate expected EV charging needs, estimated at eight million EVs in California by 2030. The legislation recognizes that improved planning and investments by utilities will support the state's policy goals, avoid delays, minimize costs, and maximize benefits. The law requires the California Energy Commission, in collaboration with the Commission, the State Air Resources Board, and other stakeholders to collect fleet data for medium and heavy-duty vehicles EVs annually, including information to estimate future fleet charging capacity needs. Utilities are required to consider the fleet data to ensure the distribution system is ready to support EV charging. Additionally, in their rate cases, utilities must identify investments made to support EV charging, and the Commission must ensure that the proposed investments contribute to preparing the grid to achieve state goals and regulations.

[181] State of California, 2022, Transportation electrification: electrical distribution grid upgrades, available at https://legiscan.com/CA/text/AB2700/id/2606993

**Table 4-2. State actions on proactive distribution system investments**

| State | Summary |
|---|---|
| CA | **Legislation: AB 2700[182], 2022 – Scope: Transportation electrification**<br>This law required utilities to proactively plan and build grid upgrades to address emerging EV load. The utility must identify those investments in their rate case for Commission approval. AB 2700 ensures that utilities use fleet data in their planning processes and requires transparency on investments made to support transportation electrification. |
| | **Legislation: SB 410[183], 2023 – Scope: Transportation and building electrification**<br>This law required the Commission to establish reasonable energization periods and to ensure utilities have adequate cost recovery mechanisms for energization costs. |
| | **Regulation: Resolution E-5167[184], 2021 – Scope: Transportation electrification**<br>This resolution enabled utilities to use their line extension policies to future-proof service connections for electric vehicle loads of non-residential customers by including additional capacity to avoid the need for upgrades in the future. |
| | **Regulation: R 23 12 008[185], 2023 – Scope: Transportation electrification**<br>This proceeding focuses on developing a framework for proactive planning for transportation electrification and will include creation of prioritization criteria for planning needs. |
| | **Regulation: A 23 05 010[186], 2023 – Scope: Rate Case (SCE)**<br>This rate case includes $1.5 billion in investments to support load growth, including transportation electrification, and consideration of different cost recovery mechanisms for proactive investments. |
| CO | **Legislation: SB 24-218[187], 2024 – Scope: Transportation and building electrification, and DER**<br>This law required utilities to upgrade the distribution system to meet transportation and building electrification, and DER growth. It requires utilities to adopt cost caps on adopting customers' responsibility for upgrades and the Commission to create a dedicated cost recovery mechanism. |
| | **Regulation: 23M-0464EG[188], 2023 – Scope: Beneficial electrification and DER**<br>This proceeding included a study of barriers to electrification and DERs and identified short- and long-term improvements needed to serve load growth. |
| MA | **Legislation: H.5060[189], 2022, Scope: Transportation and building electrification, DER, and others**<br>This law required utilities to proactively upgrade the distribution system to accommodate increased electrification and other state policy goals, including reliability and RE/DER adoption. |

182 State of California, 2022, Transportation electrification: electrical distribution grid upgrades, available at https://legiscan.com/CA/text/AB2700/id/2606993

183 State of California, 2023, Powering Up Californians Act, available at https://legiscan.com/CA/text/SB410/id/2844430

184 CPUC, 2021, Resolution E-5167 Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric request approval to establish new Electric Vehicle (EV) Infrastructure Rules and associated Memorandum Accounts, pursuant to Assembly Bill 841, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M413/K061/413061495.PDF

185 CPUC, 2023, Rulemaking 23-12-008, Order Instituting Rulemaking Regarding Transportation Electrification Policy and Infrastructure, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M529/K525/529525879.PDF

186 CPUC, 2024, Application of Southern California Edison Company (U 338-E) For Authority to Increase Its Authorized Revenues for Electric Service In 2025, Among Other Things, and to Reflect That Increase in Rates, available at https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:A2305010

187 State of Colorado, 2024, Modernize Energy Distribution Systems: Concerning measures to modernize energy distribution systems, and, in connection therewith, making an appropriation, available at https://leg.colorado.gov/bills/sb24-218

188 CO PUC, 2023, Implementation of Senate Bill 23-291, available at https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=23M-0464EG

189 State of Massachusetts, 2022, An Act Driving Clean Energy and Offshore Wind, available at https://malegislature.gov/Laws/SessionLaws/Acts/2022/Chapter179

| State | Summary |
|---|---|
| | **Regulation: 24-10, 24-11, 24-12[190], 2024 – Scope: Electric Sector Grid Modernization Plans** These proceedings include utility proactive investment proposals from National Grid, Eversource, and Until to address load growth and consideration for cost recovery mechanisms. |
| MN | **Regulation: 23-452[191] [192], 2023 – Scope: Transportation electrification and DER** This proceeding considers the need for proactive grid investments to address EV load growth and establishes a Commission-led workgroup to develop a proactive investment cost allocation framework for electrification and DER growth. |
| NC | **Regulation: E-7, SUB 1276[193], 2023 – Scope: Rate case (Duke Energy Carolinas)** This rate case included $26 million in proactive investments to serve EV fleet customers. |
| NY | **Regulation: 23-E-007[194], 2023 – Scope: Transportation electrification** This proceeding focuses on developing a proactive approach to deploying grid infrastructure for MHDEVs. |
| | **Regulation: 24-E-0364[195], 2024 – Scope: Transportation and building electrification** This proceeding expanded the scope of the above proceeding (23-E-007) and focuses on developing a proactive approach to deploy grid infrastructure to meet transportation, building, and industrial electrification needs. |

### *SB410 – Powering Up Californians Act[196]*

Passed in 2023, this legislation focused on transportation and building electrification and recognized the ongoing delays in energizing new housing developments and EV charging for light- medium- and heavy-duty vehicles. The legislation established that utilities must improve their planning, engineering, and construction of increased distribution and system capacity to improve the speed of energization and service upgrades. Additionally, the law recognized that electrification of transportation and buildings may put downward pressure on rates by spreading fixed costs over more kilowatt-hours of electricity consumed. This legislation allows utilities to request a ratemaking mechanism (a

190 Search for utility dockets at https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber, use docket numbers 24-10 (Eversource), 24-11 (National Grid), and 24-12 (Unitil).

191 Xcel Energy, 2023, 2023 Transportation Electrification Plan, available at https://www.edockets.state.mn.us/documents/%7B70808C8B-0000-CB17-9FB7-4DCDA1DB6E68%7D/download

192 MN PUC, 2023, Order of September 16, 2024, In the Matter of Xcel Energy's 2023 Integrated Distribution Plan, available at https://www.edockets.state.mn.us/documents/%7B90BDFB91-0000-C212-9EBA-FEC602C284D2%7D/download?contentSequence=0&rowIndex=12

193 Duke Energy Carolinas, 2023, Application of Duke Energy Carolinas, LLC ) For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation, Supplemental Direct Testimony of Melissa Abernathy, available at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=43af3257-4336-48d0-9830-64965fe4956c

194 NY DPS, 2023, Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure, available at https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=23-E-0070

195 NY DPS, 2024, In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure, available at https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=73733&MNO=24-E-0364

196 State of California, 2023, Powering Up Californians Act, available at https://legiscan.com/CA/text/SB410/id/2844430

memorandum or balancing account)[197] to track costs for energization projects in service after Jan 1, 2024, that exceed the cost included in the company's annual authorized revenue requirement for energization. The Commission will set a cap limiting the costs allowed under this mechanism. Through this ratemaking mechanism, utilities will be able to adjust rates annually to recover energization costs exceeding those approved in the previous rate case. In the next rate case, the Commission will determine if the costs incurred were just and reasonable, which can result in refunds to ratepayers for any disallowed costs. Through this cost recovery mechanism, the Commission is potentially reducing the utility disincentive to make the necessary investments that would result from utilities facing the regulatory lag associated with waiting until the next rate case to adjust its revenue requirement. Utilities requesting a ratemaking mechanism must agree to retain an independent third-party auditor to review the utility's business practices and procedures for energizing new customers and how the utility plans for load growth. This legislation required the Commission to establish reasonable average and maximum target energization periods and a procedure for customers to report energization delays to the Commission by September 2024. Following this requirement, the Commission established energization timelines for the state's investor-owned utilities: PG&E, SCE, and SDG&E (Table 4-3).[198]

The CPUC expects the new energization timelines to reduce maximum grid interconnection waiting times by up to 49% compared to current operations.[199] However, intervenors in this proceeding argued that the timelines are not sufficient to meet the goal of improving energization waiting times (St. John, 2024). For example, intervenors representing the EV industry argued that the energization timelines established result in little incentive for the best-performing utilities to continue to improve. Additionally, they argued that the timelines set for capacity upgrades are unlikely to accelerate project

[197] A memorandum account allows the utility to track costs not reflected in its most recent rate case, to seek recovery in a future rate case. Regulators approval of a memorandum account does not guarantee cost recovery, unless approval for cost recovery was established at the time the memorandum account was authorized. See CPUC Resolution L-100A, available at https://docs.cpuc.ca.gov/published/Final_resolution/137872.htm
A balancing account tracks actual utility costs, which may differ from the initially approved costs, which are based on estimates and projections to determine the revenue requirement. A balancing account may show an excess when the utility recovered more costs from ratepayers than actual costs or a deficit when the utility incurred more costs than recovered from ratepayers. Differences between estimated and actual costs are considered by the commission during a future rate case. See CPUC, 2024, Utility Audits, Risk and Compliance Division Standard Practice Manual, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/utility-audits--risk--and-compliance-division/documents/2023-12-26_uab-standard-practice-manual_updated_clean.pdf
[198] CPUC, 2024, Decision Establishing Target Energization Time Periods And Procedure For Customers To Report Energization Delays, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M540/K806/540806654.PDF and https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/energization
[199] CPUC, 2024, Fact Sheet CPUC Approves Decision to Support Timely Connection of New Customers to the Electrical Grid, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/energization/fact-sheet-energization-091224.pdf

deployment.[200] Similarly, the Bay Area Housing Advocacy Coalition argued that the established timelines are too long, considering historical energization timelines.[201]

**Table 4-3. CPUC energization timeline targets**

| Energization Type | Average Energization Target (calendar days) | Maximum Energization Target (calendar days) |
|---|---|---|
| Rule 15[1] | 182 | 357 |
| Rule 16[2] | 182 | 335 |
| Rule 15/16 Combined[3] | 182 | 306 |
| Rule 29/45[4] | 182 | 335 |
| Application Decision[5] | 10 | 45 |
| Main-Panel Upgrade[6] | 30 | 45 |

| Type of Capacity Upgrade | Maximum Timeline (calendar days) |
|---|---|
| New or Upgraded Circuit[7] | 684 |
| Substation Upgrade[8] | 1,021 |
| New Substation[9] | 3,242 |

Notes:

[1] Covers distribution line extensions from the substation to the secondary transformer.

[2] Covers service line extensions from the secondary transformer to the meter.

[3] Covers projects that require a distribution line extension and a service line extension.

[4] Covers projects resulting from the utilities EV Infrastructure rules (PG& and SCE: Rule 29, and SDG&E: Rule 45.

[5] This is the timeline for the utility to approve or deny a customer application for service.

[6] Covers building/home panel upgrades, including breakers, fuses, wires, and other equipment to support additional building load.

[7] This may include installing a new circuit (12 kV, 16 kV, or 33 kV), a new or upgraded kilovolt-ampere reactive capacitor, new switches, and new circuit breakers.

[8] Covers any upgrades needed within the substation perimeter, including increasing capacity, adding, or upgrading transformers, and replacing or adding substation banks.

[9] Covers all the assets necessary to build a new substation where one did not exist.

Source: Adapted from CPUC[202]

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[200] Joint EV Industry Parties, 2024, Joint EV Industry Parties Comments on Proposed Decision on Establishing Target Energization Time Periods and Procedure for Customers to Report Energization Delays, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M539/K204/539204027.PDF These comments represented ChargePoint, Tesla, FLO EV Charging, EVgo, Electrify America

[201] Bay Area Housing Advocacy Coalition, 2024, Comments of the Bay Area Housing Advocacy Coalition, dba Housing Action Coalition Regarding the Proposed Decision Establishing Target Energization Time Periods and Procedure for Customers to Report Energization Delays, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M539/K204/539204007.PDF

[202] CPUC, 2024, Fact Sheet CPUC Approves Decision to Support Timely Connection of New Customers to the Electrical Grid, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/energization/fact-sheet-energization-091224.pdf

*Regulatory action*

### *Resolution E-5167 – PG&E, SCE, and SDG&E Electric Vehicle (EV) Infrastructure Rules*[203]

Issued in 2021, this CPUC resolution focused on transportation electrification is part of the new EV infrastructure rules to provide line extensions for EV loads of non-residential customers. As part of this process, SDG&E proposed allowing a customer requesting a service upgrade to add additional capacity beyond what would otherwise be needed to meet near-term loads. SDG&E argued that upsizing the EV Service Extension, provided under its EV infrastructure rule, will avoid the need for costly upgrades in the future (Section 3, Section 3.2.4 provides more detail on this rule). ChargePoint, intervening in this proceeding, argued that SDG&E's proposal to allow the upgrade to exceed the capacity of the installed charging stations if the applicant anticipates installing higher power charging stations in the future would allow for future-proofing. Additionally, ChargePoint argued that the CPUC should not only focus on short-term costs but also recommend that the EV infrastructure rules allow site hosts to future-proof make-ready infrastructure, allowing for more efficient and cost-effective deployment. The Utility Reform Network, also intervening in this process, noted that efforts to future-proof sites by providing more infrastructure for future ports must be balanced with the need to ensure costs are reasonable and that the risk of stranded costs is mitigated.

In its resolution, the Commission directed PG&E, SCE, and SDG&E to offer future proofing and buildout of additional capacity. To be able to future-proof service upgrades, customers will need to provide a signed commitment stating that they will install additional EV chargers in the future and the approximate number they plan to install, as well as the expected timeline for installation. The Commission required utilities to submit a Tier 2 Advice Letter describing how they will implement future proofing, including how the utility will confirm that the applicant fulfilled its commitment to install additional EV charging. To our knowledge, this is the only line extension policy that considers future-proofing distribution system assets to support electrification.

### *R 23 12 008 – Order Instituting Rulemaking Regarding Transportation Electrification Policy and Infrastructure*[204]

Starting in 2023, this proceeding includes a focus on proactive planning for transportation electrification. The initial focus will be on zero emissions freight infrastructure planning. The goals include developing and refining inputs and assumptions (e.g., EV adoption forecasts, demand, EV charger types, charging behavior, and load profiles) that may be used across existing long-term generation, transmission, and distribution planning. This will also include developing prioritization criteria for transportation electrification planning needs and may include air quality impacts, cost, and

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[203] CPUC, 2021, Resolution E-5167 Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric request approval to establish new Electric Vehicle (EV) Infrastructure Rules and associated Memorandum Accounts, pursuant to Assembly Bill 841, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M413/K061/413061495.PDF

[204] CPUC, 2023, Rulemaking 23-12-008, Order Instituting Rulemaking Regarding Transportation Electrification Policy and Infrastructure, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M529/K525/529525879.PDF

transportation needs. The Commission identified initial priority areas to establish a proactive planning framework, including:[205]

- **Modelling inputs and assumptions:** develop EV modeling inputs and assumptions to support existing distribution system planning efforts and cost recovery. This may include implementing a process to assess and select inputs and assumptions, starting with those related to highway corridors. This may include aspects related to data access and sources, processes for data updates, and processes to support interagency collaboration and stakeholder inputs.
- **Prioritization:** Develop a tool to identify priority highway corridor segments for proactive EV planning and establish a process for continuously assessing proactive planning priorities.
- **Study:** Conduct a study of identified priority corridors to identify barriers to EV loads.

The Commission has not yet initiated the stakeholder process to support the development of this proactive framework and expects this proceeding to conclude in 2027.

### *A 23 05 010 – SCE 2025 Rate Case[206]*

This SCE rate case proceeding started in 2023 and includes distribution grid investments to enable electrification load growth. This is the first rate case following the passage of AB 2700 and SB 410 described above. In its rate case application, SCE recognizes rapid and widespread electrification and the need for investments in this rate case to meet load growth. It also argues that a proactive approach is needed, given the long lead time needed to deploy grid assets. Additionally, SCE argues that following a reactive, just-in-time approach would be a barrier to customer electrification, delivering decarbonization, and supporting economic growth.[207] SCE expects load growth of ~8% for the rate case period (2023-2028).

This rate case application includes load growth distribution system capital expenditures of $1.5 billion. In the previous rate case period (2019-2023), the utility proposed $841 million in distribution system capital expenditures.[208] The rate case describes capital expenditures associated with transportation electrification, which include $63 million for circuit upgrades, $183 million for new circuits, and $124 million for substations.

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205 CPUC, 2023, Rulemaking 23-12-008, Order Instituting Rulemaking Regarding Transportation Electrification Policy and Infrastructure, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M529/K525/529525879.PDF at 4-5

206 CPUC, 2024, Application of Southern California Edison Company (U 338-E) For Authority to Increase Its Authorized Revenues for Electric Service In 2025, Among Other Things, and to Reflect That Increase in Rates, available at https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:A2305010

207 SCE, 2023, 2025 General Rate Case, Vol. 1: Policy, available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2305010/6058/508571486.pdf at 21

208 SCE, 2021, 2021 Application A1908013, General Rate Case, Load Growth, Transmission Projects and Engineering. available at https://edisonintl.sharepoint.com/teams/Public/regpublic/Regulatory%20Documents/PD/CPUC/21612/SCE02V4P2.pdf?CT=1733100691162&OR=ItemsView at 33

Intervening in this proceeding, the Natural Resource Defense Council (NRDC) emphasized the possibilities for economies of scale when deploying distribution grid upgrades.[209] The utility can take that opportunity to future-proof distribution system infrastructure by deploying additional assets during routine grid upgrades to enable load growth.[210] NRDC provided an analysis of circuit and substation upgrade costs across different grid capacity needs to illustrate the potential for economies of scale (Table 4-4). Proactively deploying additional capacity during routine grid upgrades would have a smaller marginal cost (e.g., the incremental costs of the assets with greater capacity) compared to a scenario when the utility pursues proactive investments in isolation and may have to potentially duplicate the costs related to planning, permitting, and labor. Additionally, NRDC recommended that long lead times to deploy capital investments be considered when considering investments in this rate case.

**Table 4-4. NRDC analysis demonstrating distribution upgrades economies of scale using PG&E data**

Circuit and substation upgrade costs from PG&E's DDOR (PG&E 2021d) for planned distribution grid investments (Appendix J). Values for circuits are based on the reported costs of planned feeder and line section upgrades (n=187); values for substations are based on the reported costs of planned bank upgrades (n=67).

| Grid need (MW) | Circuit upgrade costs ($/kW) | | | Substation upgrade costs ($/kW) | | |
|---|---|---|---|---|---|---|
| | 25th pctl. | Median | 75th pctl. | 25th pctl. | Median | 75th pctl. |
| $< 1$ | 445.71 | 1,875.00 | 5,791.67 | 9,935.00 | 18,863.43 | 28,982.79 |
| $\geq 1$ & $< 2$ | 251.84 | 1,368.89 | 2,092.89 | 3,594.99 | 4,740.03 | 6,980.09 |
| $\geq 2$ & $< 4$ | 196.76 | 673.35 | 1,447.55 | 2,927.93 | 3,978.38 | 4,468.75 |
| $\geq 4$ & $< 8$ | 268.65 | 438.14 | 785.30 | 1,137.16 | 2,004.70 | 2,570.87 |
| $\geq 8$ | 237.23 | 367.85 | 586.32 | 634.01 | 887.62 | 1,189.14 |

Source: From NRDC[211]

Given the uncertainty attendant to proactive investments, intervenors recommended that SCE recover its costs using a two-way balancing account, which offers the flexibility to recover actual costs if those are greater than initially approved by the Commission. SCE disagreed with the proposal for using a balancing account for these investments, describing the proposal as inconsistent with the role of memorandum accounts, which are meant to track costs that, for various reasons, could not be included in the rate case. SCE argued that, in this instance, the costs are proposed in the rate case.[212] This proceeding is still open as of January 2025, and a Commission order has not been issued.

[209] NRDC, 2024, Opening Testimony SCE 2025 General Rate Case, available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2305010/7098/526567018.pdf
[210] NRDC, 2024, Opening Testimony SCE 2025 General Rate Case, available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2305010/7098/526567018.pdf
[211] NRDC, 2024, Opening Testimony SCE 2025 General Rate Case, available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2305010/7098/526567018.pdf
[212] SCE, 202, 2025 General Rate Case, Rebuttal Testimony, Results of Operations, available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2305010/7236/529525927.pdf at 77

### 4.3.2 Colorado

*Legislative action*

***SB24-218 - Powering Up Colorado[213]***

Enacted in 2024, this legislation focused on transportation and building electrification and DERs. This law recognized that consumer demand for DERs and electrification is expected to increase and may start exceeding available distribution system capacity. To address this concern, the legislature established that utilities must upgrade the distribution system as needed and in time to support electrification and decarbonization goals. Specifically, the law requires utilities to start collecting data to inform future energization timelines and adopt cost caps for individual customers' responsibility for distribution upgrades. For instance, the legislation states that residential customers energizing transportation or building loads must not pay for distribution system upgrade costs. This may result in changes to existing line extension policies (Section 3 discusses line extension policies and their role in supporting load growth). Additionally, the law requires the Commission to establish:

- A target average and maximum energization timeline.
- Rules for interconnection, energization, and electrification of new homes, including timeframes to respond to cost projection requests, the reliability of the utility cost estimates, and reasonable construction schedules.
- Maximum individual customer cost caps or fees for interconnection or energization of all resources. The legislation established that residential should be exempt from payment of system upgrade fees.
- A cost recovery mechanism. Utilities may recover costs incurred starting January 2026 through a grid modernization adjustment clause on an annual basis.

in response to the legislation, the Commission granted Xcel Energy approval to use its existing Transmission Cost Adjustment rider to recover proactive distribution investment costs necessary to support the law's objective in 2024 and 2025 and to implement the Grid Modernization Adjustment Clause for cost recovery in 2026.[214] [215] The legislation set retail rate impact caps of 0.5% for 2024 and 1.25% in 2025.[216] Xcel Energy's Transmission Cost Adjustment mechanism allows for the recovery of transmission-related capital costs that are not recovered through utility base rates set in the most recent rate case. The tariff for this mechanism was adjusted following the Commission's approval to

[213] State of Colorado, 2024, Modernize Energy Distribution Systems: Concerning measures to modernize energy distribution systems, and, in connection therewith, making an appropriation, available at https://leg.colorado.gov/bills/sb24-218

[214] CO PUC, 2024, Decision C24-0720 Commission Decision Providing Direction For Future Filings And Closing Proceeding, available at https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_dec=31315&p_session_id=

[215] Xcel Energy, 2024, Transmission Cost Adjustment Tariff, available at https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=1030352&p_session_id=

[216] State of Colorado, 2024, Modernize Energy Distribution Systems: Concerning measures to modernize energy distribution systems, and, in connection therewith, making an appropriation, available at https://leg.colorado.gov/bills/sb24-218

recover distribution system upgrade costs resulting from compliance with SB 24-218.[217] These costs are recovered from customer classes based on a dollar per kW charge for rates with a demand component and based on a dollar per kWh for rates without a demand component.

*Regulatory action*

### 23M-0464EG - Study of potential barriers to beneficial electrification and DERs[218]

Initiated in 2023, the purpose of this proceeding was to complete the study requested in SB23-291[219] on barriers to electrification and deployment of DER. Throughout this proceeding, intervenors shared concerns with the Commission about Xcel Energy's inability to promptly connect new load in certain areas (e.g., the Denver Metro area). Customers reported that their projects in Xcel Energy territory would bear significant costs, face long timelines, or both. As a result of this proceeding, the Commission found that current practices expand the distribution system in a reactive, piecemeal way. The Commission found that existing processes may obfuscate, delay, or disincentivize customer adoption of beneficial electrification measures and may also pose a barrier to additional electrified housing and other developments that would serve the public interest. The Commission recommended that Xcel prioritize improving its ability to serve new or upgraded loads, primarily through better forecasting and planning, improved and more transparent communication, and timely execution of distribution system upgrades.

## 4.3.3 Massachusetts

*Legislative action*

### *H.5060 – An Act Driving Clean Energy and Offshore Wind[220]*

Passed in 2022, this law requires Massachusetts utilities to submit Electric Sector Grid Modernization Plans (ESMPs). The plans must include actions to proactively upgrade the distribution system and, where applicable, transmission system to improve reliability, communications, and resilience; enable the adoption of RE and DERs; promote storage and electrification technologies; prepare for climate-driven impacts; accommodate increased electrification; and minimize or mitigate impact on ratepayers.

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[217] The retail rate impact caps limit the costs the utility can recover through the Transmission Cost Adjustment Rider. See Xcel Energy, 2025, Colorado Electric Tariff, available at https://xcelnew.my.salesforce.com/sfc/p/#1U0000011ttV/a/8b000002Y8xL/kYe61yf.9xyigvh2701Az49XLgU2izDS8ShGaCXiwsQ at 315

[218] CO PUC, 2023, Implementation of Senate Bill 23-291, available at https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=23M-0464EG

[219] State of Colorado, 2023, Utility Regulation: Concerning the public utilities commission's regulation of energy utilities, and, in connection therewith, making an appropriation, available at https://leg.colorado.gov/bills/SB23-291

[220] State of Massachusetts, 2022, An Act Driving Clean Energy and Offshore Wind, available at https://malegislature.gov/Laws/SessionLaws/Acts/2022/Chapter179

*Regulatory action*

### *24-10, 24-11, 24-12 – ESMP for National Grid, Eversource, and Until*[221]

Initiated in 2024, these proceedings included the inaugural Electric Sector Grid Modernization Plans. In their filings, the utilities indicated considerable growth expected in customer load due to EV, heat pump, and DER technology adoption, and the need to upgrade the system to address capacity constraints. For example, Figure 4-3 compares National Grid's available substation capacity in 2023 to expected capacity constraints by 2035 if no system upgrades are made.

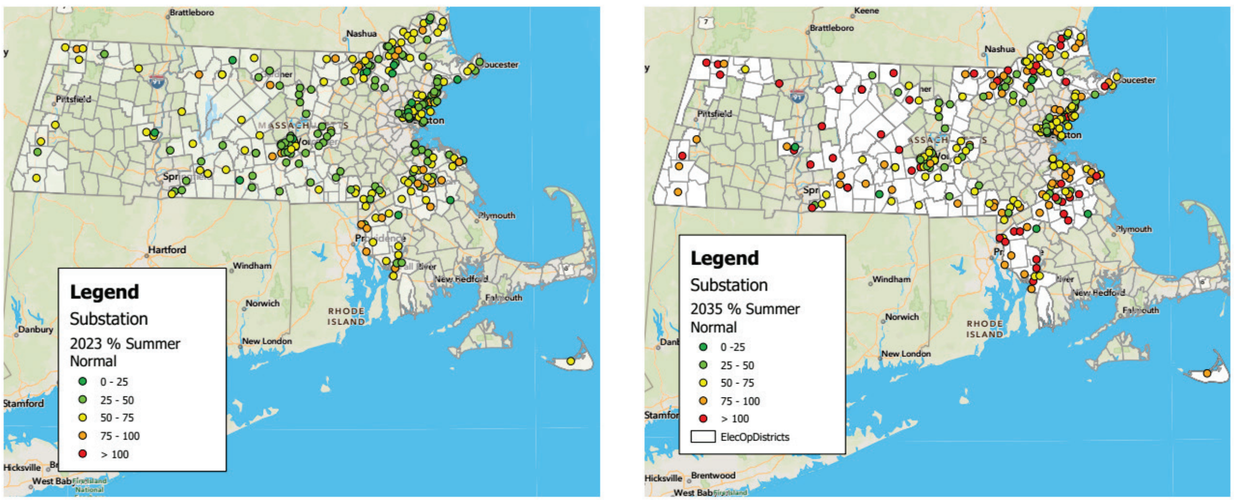


**Figure 4-3. National Grid's substation capacity in 2023 and 2035 if no upgrades are made**

Source: From National Grid[222]

To address expected grid needs and the law's requirements to proactively upgrade the distribution system, the utilities proposed the following investments:

- **National Grid:** Proposed $1.5 billion in investments to support network infrastructure upgrades, including substation and distribution line upgrades and expansion for electrification and DER. Between 2025 and 2029, National Grid proposed to deliver 13 substation upgrades or rebuilds, enabling 800 MW of capacity. Between 2030 and 2034, National Grid proposed to deliver 26 new or rebuilt substations, enabling over 2,900 MW of capacity.[223]

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[221] Search for utility dockets at https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber, use docket numbers 24-10 (Eversource), 24-11 (National Grid), and 24-12 (Unitil).

[222] National Grid, 2024, Electric Sector Modernization Plan, Future Grid Plan: Empowering Massachusetts by Building a Smarter, Stronger, Cleaner and More Equitable Energy Future, available at https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan.pdf at 17

[223] National Grid, 2024, Electric Sector Modernization Plan, Future Grid Plan: Empowering Massachusetts by Building a Smarter, Stronger, Cleaner and More Equitable Energy Future, available at https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan.pdf

- **Eversource:** Proposed to invest $4.5 billion in capital expenditures, including capacity upgrade projects to support peak load. Between 2025 and 2029, Eversource proposed to upgrade six and construct five substations, adding 1.8 GW of capacity. Between 2030 and 2034, Eversource proposed to upgrade two and construct nine substations, adding 3.4 GW of capacity.[224]
- **Unitil:** Proposed $49 million in capital expenditures. Between 2025 and 2029, Until proposed to upgrade one substation. Between 2030 and 2034, Unitil proposed to upgrade one and construct one substation.[225]

In August 2024, the Commission approved the first round of ESMPs, allowing for a targeted cost recovery mechanism instead of recovering costs through distribution rates.[226] The Commission recognized that cost recovery through distribution rates could delay or diminish the utilities' interest in pursuing the proactive investments identified in their ESMPs. The details of this targeted cost recovery mechanism are currently being considered in an ongoing proceeding. In this proceeding the Commission is also studying innovative approaches for cost recovery via distribution rates to support the proactive investment goal set in Massachusetts law, discussed above. The scope of this proceeding includes:[227]

- Determining the costs eligible for cost recovery
- Developing cost containment approaches (e.g., budget caps or revenue caps)
- Developing information requirements for cost recovery requests
- Establishing processes to evaluate alternatives and approaches to changing circumstances during the five-year ESMP duration
- Implementing innovative mechanisms to support cost minimization for ratepayers
- Considering when the ESMP targeted cost recovery mechanisms may become obsolete and no longer needed

[224] Eversource, 2024, Electric Sector Modernization Plan, Accelerating a Just Transition to a Reliable and Resilient Clean Energy Future, available at https://www.eversource.com/content/docs/default-source/default-document-library/eversource-esmp%20.pdf

[225] Until, 2024, Electric Sector Modernization Plan, available at https://unitil.com/sites/default/files/2024-01/Unitil-ESMP-2025-2050-DPU-FINAL.pdf

[226] MA DPU, 2024, Order August 29, 2024, Docket 24-10 Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of its Electric Sector Modernization Plan filed pursuant to G.L. c. 164, § 92B., 24-11 Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan filed pursuant to G.L. c. 164, § 92B., and 24-12 Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of its Electric Sector Modernization Plan filed pursuant to G.L. c. 164, § 92B., available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/19554888 at 495-496

[227] MA DPU, 2024, Order August 29, 2024, Docket 24-10 Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of its Electric Sector Modernization Plan filed pursuant to G.L. c. 164, § 92B., 24-11 Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan filed pursuant to G.L. c. 164, § 92B., and 24-12 Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of its Electric Sector Modernization Plan filed pursuant to G.L. c. 164, § 92B., available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/19554888 at 463

### 4.3.4 Minnesota

*Regulatory action*

#### *23-452 – Xcel Energy 2023 Transportation Electrification Plan and Integrated Distribution System Plan*[228]

In its 2023 Transportation Electrification Plan, Xcel Energy discussed how proactive grid reinforcement in anticipation of EV adoption growth will be necessary to prepare for increased fleet electrification. In its distribution system plan five-year budget, starting in 2025, Xcel Energy included $190 million for proactive system upgrades to increase DER hosting capacity.[229]

The utility recognizes the following challenges for adding capacity to meet growing EV loads:[230]

- The scale and timing of commercial EV loads (e.g., fleets) is uncertain
- Commercial EV loads do not impact the grid uniformly, as these are often concentrated in specific locations such as fleet clusters and public charging hubs
- Lead times for deploying distribution system infrastructure can be long (from one to ten years)

As part of its actions to streamline and improve internal processes, Xcel Energy created a team of EV-focused distribution engineers to understand how, when, and where the accelerating onset of EV load will likely impact the distribution system.[231]

In this proceeding, the Commission also decided to establish and lead a workgroup to develop a framework for cost allocation and proactive investments in system upgrades for electrification and DERs, with a goal completion date of July 1, 2025.[232] Topics to address through the workgroup include:

- How to allocate the costs of proactive upgrades
- How to ensure any proactive upgrades are distributed equitably throughout a utility's service territory
- If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for specific customer classes

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[228] Xcel Energy, 2023, 2023 Transportation Electrification Plan, available at https://www.edockets.state.mn.us/documents/%7B70808C8B-0000-CB17-9FB7-4DCDA1DB6E68%7D/download

[229] Xcel Energy, 2023, E002/M-23-452, Transportation Electrification Plan 2023 Integrated Distribution Plan Xcel, available at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={B07D8C8B-0000-C521-A8F5-FE267238317D}&documentTitle=202311-200132-10 at 94

[230] Xcel Energy, 2023, E002/M-23-452, Transportation Electrification Plan 2023 Integrated Distribution Plan Xcel, available at https://www.edockets.state.mn.us/documents/%7B70808C8B-0000-CB17-9FB7-4DCDA1DB6E68%7D/download?contentSequence=0&rowIndex=102 at 20

[231] Xcel Energy, 2023, E002/M-23-452, Transportation Electrification Plan 2023 Integrated Distribution Plan Xcel, available at https://www.edockets.state.mn.us/documents/%7B70808C8B-0000-CB17-9FB7-4DCDA1DB6E68%7D/download?contentSequence=0&rowIndex=102 at 46

[232] MN PUC, 2023, Order of September 16, 2024, In the Matter of Xcel Energy's 2023 Integrated Distribution Plan, available at https://www.edockets.state.mn.us/documents/%7B90BDFB91-0000-C212-9EBA-FEC602C284D2%7D/download?contentSequence=0&rowIndex=12

- How a proactive upgrade program would integrate with a utility's other planned distribution investment programs
- How a utility's other capacity programs and changes to distribution standards impact available hosting capacity
- How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption
- Whether there should be changes to any of a utility's service policy provisions, such as contributions in aid of construction

### 4.3.5 North Carolina

*Regulatory action*

#### E-7, SUB 1276 – Duke Energy Carolinas 2023 Rate Case[233]

In its 2023 rate case, Duke Energy recognized the challenge associated with being able to readily serve fleets transitioning to EV technologies. To address this concern, Duke Energy analyzed fleet clusters in North Carolina to determine the probability of adopting fleet EV technology and identify potential areas of concern that could disrupt power operations and fleet operators' goals. These areas of concern were determined with support from planning engineers and EV fleet experts. Duke identified six areas of concern and scoped project proposals, including the required investment level and estimated in-service dates (Table 4-5). Duke Energy received Commission approval to address the six areas of concern proposed and deploy ~$26 million in proactive capital investments. These investments will add 100 MW of system capacity; costs will be recovered through base rates.[234]

For each area of concern, Duke Energy identified existing fleets of internal combustion engine vehicles expected to convert to EV technology through 2029. For example, in Charlotte, the utility identified ten fleets, which are expected to add 15.8 MW of substation load by 2029 from the adoption of light-duty, medium-duty, and heavy-duty EVs. To support the expected load growth, Duke Energy identified the need for $9.8 million in capital investments, including reconductoring and upgrading feeders in two substations, extending feeders and moving taps, installing a new voltage regulator, and extending a duct bank to transfer load to another substation.[235]

[233] Duke Energy, 2023, Application of Duke Energy Carolinas, LLC ) For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation, Supplemental Direct Testimony of Melissa Abernathy, available at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=43af3257-4336-48d0-9830-64965fe4956c

[234] Duke Energy, 2023, Application of Duke Energy Carolinas, LLC ) For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation, Supplemental Direct Testimony of Melissa Abernathy, available at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=43af3257-4336-48d0-9830-64965fe4956c

[235] Duke Energy, 2023, Supplemental Direct Testimony of Brent C. Guyton for Duke Energy Carolinas, LLC, available at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=6214b86e-4b0a-4f78-a1c9-885540a629a8 at 72

**Table 4-5. Duke Energy Carolinas project proposals to address areas of concern for EV fleets**

| Project | Zone | MW | Cap | O&M | Estimated ISD |
|---|---|---|---|---|---|
| Charlotte Fleet EV Cluster Reconductor | Central | 15.8 | $9,827,649 | $264,330 | 11/2026 |
| Pineville Fleet EV Cluster Reconductor | Central/Pee Dee | 6.3 | $640,282 | $17,221 | 11/2026 |
| Kernersville Fleet EV Cluster Reconductor | Triad | 20.7 | $4,805,951 | $129,264 | 11/2026 |
| Greensboro Fleet EV Cluster Reconductor | Triad | 9.4 | $489,312 | $13,161 | 11/2026 |
| High Point Fleet EV Cluster Reconductor | Triad | 8.6 | $2,673,703 | $71,913 | 11/2026 |
| RTP Fleet EV Cluster Reconductor | Triangle North | 40.9 | $8,078,498 | $217,284 | 11/2026 |
| | **Total** | **101.7** | **$26,515,394** | **$713,173** | |

Source: From Duke Energy Carolinas[236]

### 4.3.6 New York

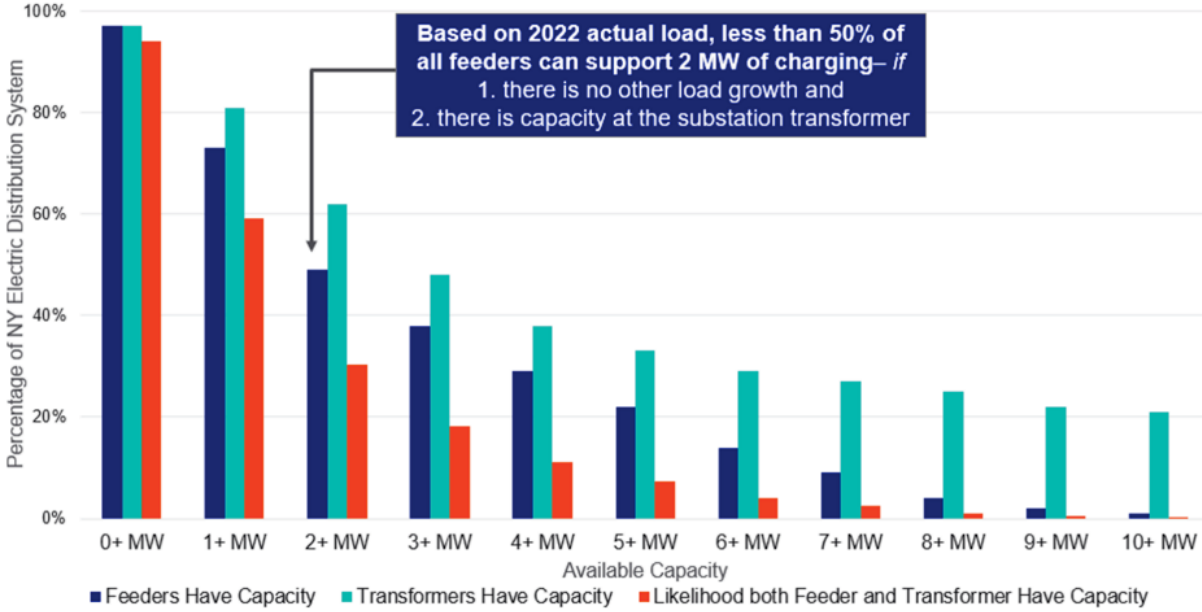
*Regulatory action*

***23-E-007 – Proactive investments to enable medium- and heavy-duty EVs[237]***

Initiated in 2023, this proceeding focuses on MHDEVs. The Commission aims to establish proactive planning approaches to ensure that grid infrastructure is prepared to accommodate growing EV charging needs. This proceeding seeks to remove barriers to the efficient and timely development of charging infrastructure and considers revisions to utility planning for proactive investments, particularly in high-priority areas. Proactive planning approaches must anticipate the location and magnitude of future demand. To be effective, a proactive planning process will be able to identify high-priority infrastructure upgrades before issues from capacity limitations arise. For example, Figure 4-4 provides insight into existing feeder capacity to accommodate EVs in National Grid's service territory. This analysis found that less than 50% of the feeders can support an additional 2 MW in charging, assuming no other load growth occurs and that the substation has available transformer capacity. In this case, determining the location of hotspots for EV charging, including clusters of existing depots and high-traffic destinations such as highway rest areas, can help identify relevant locations for proactive investments.

[236] Duke Energy, 2023, Supplemental Direct Testimony of Brent C. Guyton for Duke Energy Carolinas, LLC, available at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=6214b86e-4b0a-4f78-a1c9-885540a629a8 at 72

[237] NY DPS, 2023, Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure, available at https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=23-E-0070




Source: National Grid Internal Analysis
Note: Likelihood both feeder and transformer have capacity is a simple multiplication of the other two bars for illustrative purposes.

**Figure 4-4. National Grid's analysis of available feeder and transformer capacity for load growth**

Source: From National Grid[238]

In this proceeding, NY Joint Utilities proposed a framework for proactive planning and grid investments that includes identifying concentrated EV and MHDV loads and developing a proactive investment plan. The proposed plan development process includes the following:

- **Identifying and promoting "areas of capacity"** where grid capacity exists today and is adequate to meet near-term transportation needs.
- **Identifying and preparing the grid in "areas of need"** where customers' and communities' near-term EV needs for charging will exhaust all excess capacity. Table 4-6 describes National Grid's potential characteristics and planning actions to consider in "areas of capacity" and "areas of need"
- **Establishing investment plans** that are prioritized and sequenced based on clear characteristics

### *24-E-0364 – Proactive investments for infrastructure upgrades[239]*

In 2024, the Commission found that the planning needs of the electrical grid exceeded the scope of the MHDEV proceeding discussed above and started a proactive planning proceeding, which is expected to

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238 National Grid, 2023, Docket 23-E-007, National Grid Supplemental Comments, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C03F9188-0000-CF12-8B91-BB760DB518BF} at 15

239 NY DPS, 2024, In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure, available at https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=73733&MNO=24-E-0364

conclude in 2026. This proceeding direct the investor-owned utilities to develop a proactive planning framework for EV and building electrification filing, and an urgent grid needs upgrades filing.

**Table 4-6. National Grid's proactive planning approach for "areas of capacity" and "areas of need."**

| | Areas of Capacity | Areas of Need |
|---|---|---|
| **Description** | Areas where near-term customer and community needs for EV and MHDV charging do not require significant grid or interconnection upgrades. | Areas where customer and community needs for EV and MHDV charging do require significant grid or interconnection upgrades. |
| **Potential Characteristics** *(suggested / non-exhaustive)* | • Can support significant EV load, e.g., in areas with fast-charging, higher fleet concentrations, trucking corridors or transit<br>• Benefits may be provided to multiple fleets and/or station operators<br>• Benefits may be provided to host and neighboring communities, including Disadvantaged Communities[22]<br>• Other potential benefits may be provided where applicable, e.g., providing capacity for other growing load | |
| | • Existing grid capacity or<br>• Planned grid capacity growth (e.g., planned asset condition work) | • Existing or forecasted upstream grid constraints or<br>• Significant interconnection constraints for individual customers<br>• May offer potential for multi-value upgrades (e.g., anticipated asset condition work) |
| **Proactive Planning Action** | Maximize available grid capacity by supporting customers with education, tools, and make-ready infrastructure incentives. | Eliminate grid infrastructure barriers to EV charging through proactive grid investments which create capacity for charging at the pace needed. |

Source: From National Grid[240]

Following this requirement, the New York Joint Utilities submitted their "Long-term Proactive Planning Framework"[241] for Commission consideration. The proposed framework includes planning cycles, each including the following stages:

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240 National Grid, 2023, Docket 23-E-007, National Grid Supplemental Comments, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C03F9188-0000-CF12-8B91-BB760DB518BF} at 10

241 New York Joint Utilities, 2024, Docket 24-E-0364, Joint Utilities' Long-Term Proactive Planning Framework, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={60C3C193-0000-C42C-9162-2B10D1624579}

- **Load assessment:** This stage includes the development of analytical tools to identify areas where electrification load growth may occur rapidly. The utilities propose to leverage data from load forecasts developed in other processes, such as utility electric peak demand studies and NYISO studies; granular load growth studies focused on localized load growth; and other sources including State agency studies. This stage will also include stakeholder engagement through an annual technical conference.
- **Planning and solution design:** This stage consists of analyzing load assessment outputs and existing grid conditions to identify infrastructure investment needs.
- **Project eligibility and prioritization criteria:** Proposed eligibility criteria include determining if the proposed investment is necessary to support electrification load growth, and if the investment must be pursued in the near-term (within 18 months of being proposed to the Commission). Table 4-7 includes the utilities' proposed prioritization criteria.
- **Proposal and authorization of projects:** In this stage, utilities would submit project proposals to the Commission for approval. The utilities propose two investment categories, one for small projects and one for large projects. Projects considered large would be submitted annually for Commission approval, while small projects would operate on a two-year budget. The utilities argue that this approach allows for more adaptability to changing policy and market drivers. Figure 4-5 illustrates the two-category investment process proposed.

The utilities expect the first cycle of proactive planning to result in proposed projects by the end of 2025.

In their urgent grid needs upgrades filing, the utilities proposed investments that may require deployment before the completion of the framework described above. Consolidated Edison proposed ~$856 million in urgent grid upgrades to support transportation and building electrification.[242] National Grid proposed ~$460 million in urgent grid upgrades to meet transportation and building electrification load growth infrastructure needs.[243] New York State Electric & Gas and Rochester Gas and Electric proposed $554 million in urgent upgrades ($468 million for NYSEG and $86 million for RG&E).[244] Central Hudson determined in consultation with the Commission that no project fit the urgency criteria determined by the Commission, and as a result did not propose urgent upgrades.[245]

242 Consolidated Edison, 2024, Docket 24-E-0364, Urgent Projects Proposal, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={50672793-0000-CA1E-A2DB-0BF4221D3E15}

243 National Grid, 2024, Docket 24-E-0364, , available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={60862793-0000-C755-99D5-45B99DF5AC13}

244 New York State Electric & Gas and Corporation and Rochester Gas and Electric, 2024, Docket 24-E-0364, Petition of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation for Approval of Urgent Upgrade Projects and Associated Cost Recovery, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D0586A93-0000-C68A-9C46-31CE3784468F}

245 Central Hudson, 2024, Docket 24-E-0364 Upgrade Letter, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={20E76E93-0000-C513-B909-E59A3339D571}

**Table 4-7. New York Joint Utilities proposed proactive investment prioritization criteria**

| Proactive Planning Prioritization Criteria | Description |
|---|---|
| Degree of Certainty | Demonstrate an appropriate degree of certainty of the need for each project based on location, magnitude, and timing of expected load. Utilities will seek to forecast load aligning with concrete policy mandates. |
| Consideration of Risks and Benefits | Demonstrate how a Proactive Planning project (1) is appropriately sized to address risks related to forecast uncertainty and (2) minimizes risks of delayed action and/or considers benefits of early action in making proposed upgrades. This criterion includes information such as a project's phasing and expandability potential. |
| Alignment with State Law Objectives | Demonstrate consistency with the objectives of State laws, such as the CLCPA regarding greenhouse gas emissions reductions, impacts to Disadvantaged Communities, and State electrification policies. Where projects will affect one or more Disadvantaged Communities, proposals will discuss how projects will impact and benefit those communities (e.g., through capacity created for beneficial electrification, localized reductions in emissions, and noise pollution abatement). |
| Qualitative and/or Quantitative Benefits | Demonstrate direct and indirect project benefits, including enabling electrification consistent with policy and improvements in resiliency and reliability. |
| Costs | Assess costs, including initial capital and operating expenditures. |
| Availability of Alternatives | Assess inclusion of alternative designs, advanced technologies, or bridge-to-wires solutions. |
| Locations or Site Types | Leverage stakeholder engagement throughout this proceeding, including Annual Stakeholder Technical Conferences, to provide qualitative input into areas or site types to prioritize (e.g., Industrial Business Zones in New York City may be priority locations within Con Edison's territory, based on input from the City of New York)[59] to supplement utility planning and solution design. |
| Project Timelines and Financials | Assess project timelines and financials (e.g., revenue requirement over time). |

Source: From New York Joint Utilities[246]

[246] Table 3 at 28, see New York Joint Utilities, 2024, Docket 24-E-0364, Joint Utilities' Long-Term Proactive Planning Framework, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={60C3C193-0000-C42C-9162-2B10D1624579}

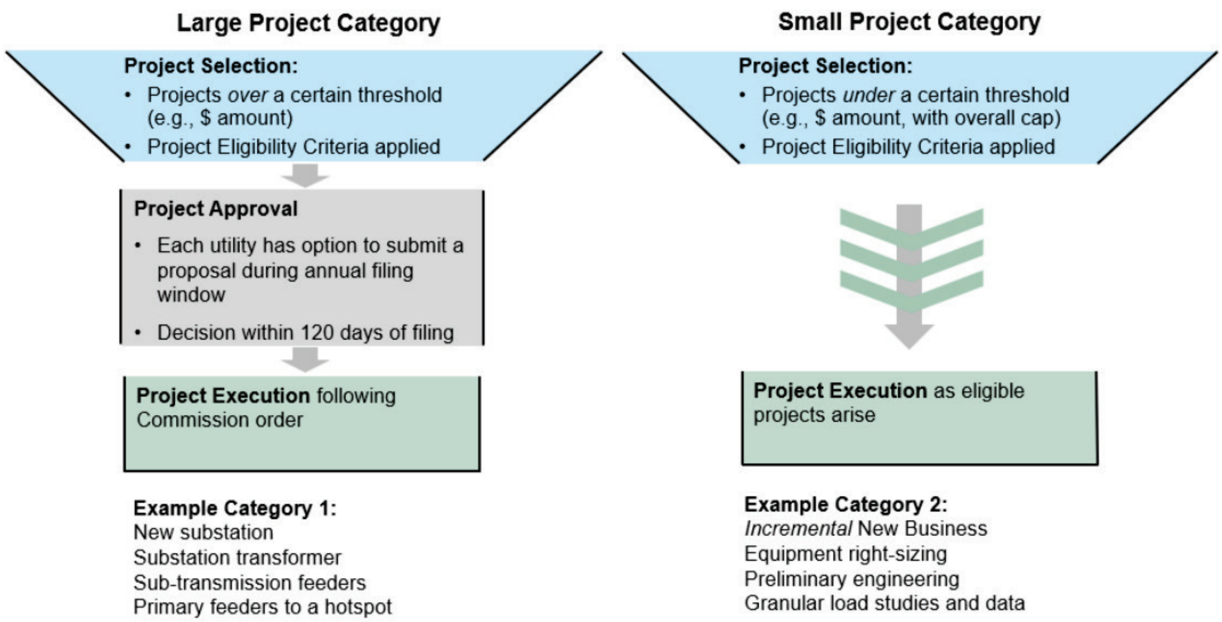


**Figure 4-5. New York Joint Utilities two-category investment process proposed**

Source: From New York Joint Utilities[247]

In addition to the individual filings, the New York Joint Utilities proposed a common project evaluation and funding approach.[248] Proposed project evaluation criteria include demonstrating that proposed upgrades:

- are necessary to meet electrification load growth;
- are urgently needed;
- have sufficient certainty that in load growth will occur in the scale, location, and timing reflected in investment proposals; and
- are designed to reduce the potential risk of over- or under-building.

The utilities proposed to continue using existing cost allocation principles reflected in each utility's tariffs and rate cases. The utilities propose to recover costs through a surcharge on customers' bills to expedite cost recovery to meet the Commission's order goals. Additionally, the utilities propose to have the option to include 100% of the Construction Work in Progress costs in the rate base. This expedites cost recovery, as typically, Construction Work in Progress costs (i.e., all the costs incurred with the construction of distribution system assets) are only added to the rate base when the asset is placed in

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[247] Table 3 at 28, see New York Joint Utilities, 2024, Docket 24-E-0364, Joint Utilities' Long-Term Proactive Planning Framework, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={60C3C193-0000-C42C-9162-2B10D1624579}

[248] New York Joint Utilities, 2024, Docket 24-E-0364 Joint Utilities' Proactive Planning Urgent Upgrade Projects Evaluation and Funding Proposal, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={906E2793-0000-C215-8D5C-BCE2A871DA30}

service (Enerdynamics, 2025c). Alternatively, the utilities request approval to earn an Allowance for Funds Used During Construction, through which the utilities are able to capitalize financing costs associated with constructing new assets, to be recovered when the asset is put into service (Enerdynamics, 2025a). Utilities provided additional details on cost recovery in their individual upgrade proposals. For example, New York State Electric & Gas and Rochester Gas and Electric propose that the Construction Work in Progress costs of these urgent upgrades be included in the rate base or a similar cost recovery mechanism that would allow recovery while in construction. In their proposal, the utilities discuss existing cash flow challenges and the difficulty of pursuing additional capital investments without timely cost recovery. The utilities indicate that Commission approval to include these costs in the rate base could save customers the cost of the utilities facing a credit downgrade. The utilities propose to create a new customer bill surcharge to recover project costs until these are added to the rate base in the next rate case.[249]

## 4.4 Risk management options

Regulators may benefit from understanding and implementing risk management approaches as the need for proactive investments to address load growth increases. This section describes a range of procedural, financial, and public policy risk management options that regulators may consider as part of their evolving toolkit of proactive investment enabling practices. Some of these options are mostly conceptual. Regulatory practice in proactive distribution system investments will require considerable development in the coming years, and implementation of these concepts involves details that we do not address here.

### 4.4.1 Procedural risk management options

#### *Require access to and reporting of granular grid data and a process for close monitoring of electrification-driven load growth grid needs*

Regulators may establish new requirements to ensure data and reporting practices evolve to support transparency and decision-making for proactive investments. This can contribute to increased confidence in the inputs supporting proactive investment proposals. For instance, California utilities must consider MHDEV fleet data to ensure the distribution system can support EV charging.[250] Granular grid data and reporting practices may also evolve to provide more transparency on energization waiting times, for which regulators may also set standardized timelines. For example, legislation in California[251]

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[249] New York State Electric & Gas and Corporation and Rochester Gas and Electric, 2024, Docket 24-E-0364, Petition of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation for Approval of Urgent Upgrade Projects and Associated Cost Recovery, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D0586A93-0000-C68A-9C46-31CE3784468F}

[250] State of California, 2022, Transportation electrification: electrical distribution grid upgrades, available at https://legiscan.com/CA/text/AB2700/id/2606993

[251] State of California, 2023, Powering Up Californians Act, available at https://legiscan.com/CA/text/SB410/id/2844430

and Colorado[252] required regulators to set maximum and average target timelines for utilities to serve new or upgraded loads. In California, the commission recently established its timeline by drawing on granular utility data.[253] States with utility hosting capacity maps may be able to leverage their experience developing data requirements and platforms when implementing data access and reporting processes to support proactive investments.[254]

### *Require new or adapted forecasting processes to validate future needs assessment and minimize the risk of over-investing*

Regulators can establish new requirements or adapt existing distribution system planning processes to enhance load forecasting capabilities. Enhanced forecasting may reduce the uncertainty of expected load growth and support the right-sizing of proactive investments, mitigating the risk of over-investing. Improved forecasting processes may include lengthening the forecast horizon, enabling utilities and regulators to develop scenarios useful for evaluating proactive investment proposals (EPRI, 2024b). For example, in Massachusetts, utilities filing ESMPs must consider three planning horizons for electricity demand: 5- and ten year demand forecasts and a long-range demand assessment through 2050 that accounts for trends impacting load, including EV and heat pump adoption.[255] Process improvements may also include ensuring forecast and input alignment across gas and electric planning processes to ensure electric proactive investments consider gas system characteristics, such as trends in customer demand (LeBel et al., 2025).

### *Require third parties to perform or validate load-growth studies and/or utility proposals*

Regulators can require utilities to engage a third party to conduct independent analyses or validate utility-conducted analyses supporting proactive investment proposals. Third-party validation may increase confidence in utility proposals and may help mitigate utility capital investment bias. Additionally, it may promote greater transparency for regulators and stakeholders and greater utility accountability to propose reasonable investments. For example, in California, utilities requesting a dedicated cost recovery mechanism for distribution system upgrades to support energization must work with a third-party independent auditor to review utility business practices and procedures for serving new loads and how the utility plans for load growth.[256] In Massachusetts, the Grid Modernization Advisory Council (GMAC) reviews utility ESMPs. The GMAC has a minimum of 80 days to conduct their review. Utilities must submit their plan for review no later than 150 days prior to submission to the Commission, and the GMAC must provide feedback no later than 70 days before the

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[252] State of Colorado, 2024, Modernize Energy Distribution Systems: Concerning measures to modernize energy distribution systems, and, in connection therewith, making an appropriation, available at https://leg.colorado.gov/bills/sb24-218

[253] CPUC, 2024, Decision Establishing Target Energization Time Periods And Procedure For Customers To Report Energization Delays, Appendix A Statewide Energization Timelines Analyses Report, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M540/K719/540719251.PDF

[254] U.S. DOE, U.S. Atlas of Electric Distribution System Hosting Capacity Maps, available at https://www.energy.gov/eere/us-atlas-electric-distribution-system-hosting-capacity-maps

[255] State of Massachusetts, 2022, An Act Driving Clean Energy and Offshore Wind, available at https://malegislature.gov/Laws/SessionLaws/Acts/2022/Chapter179

[256] State of California, 2023, Powering Up Californians Act, available at https://legiscan.com/CA/text/SB410/id/2844430

plan is due to the Commission. Utilities must address how feedback received was implemented, modified, or rejected in their investment plans.[257]

While third-party validation can provide considerable value, regulators must weigh that value against the time and expense required to engage third parties. Regulators may decide to focus third-party validation on certain aspects of proactive investment planning and analysis, and not others, based on such considerations. For example, the New York Joint Utilities, in their December 2024 long-term proactive planning framework, propose to include load studies performed by third parties, which may include studies by the International Council on Clean Transportation or the Electric Power Research Institute (EPRI) EVsScale2030.[258] [259] This involvement comes at the forecasting stage, which may create less delay than would third-party vetting of project execution (though such vetting may well be appropriate in some cases).[260]

### *Require a forward-looking analysis of the locational value of NWAs or flexible interconnection agreements to defer distribution system costs or provide bridge-to-wires solutions*

Regulators can require utilities to consider NWAs or flexible interconnection agreements as part of the process for identifying and deploying cost-effective, proactive investments. Proactively investing in NWAs may, in some cases, reduce or mitigate the need for system capacity additions (EPRI, 2024a). Alternatively, NWAs may be able to act as a cost-effective bridge-to-wires solution to address capacity constraints and reduce the scale of traditional capacity infrastructure needed (Brehm et al., 2024).[261] These solutions may include, for example, storage sited in strategic locations to support EV loads.[262] NWAs may enable utilities to serve new loads faster than deploying traditional distribution system infrastructure, though there may also be cases where the reverse is true. Table 4-8 illustrates the

[257] State of Massachusetts, 2022, An Act Driving Clean Energy and Offshore Wind, available at https://malegislature.gov/Laws/SessionLaws/Acts/2022/Chapter179

[258] New York Joint Utilities, 2024, Docket 24-E-0364 Joint Utilities' Proactive Planning Urgent Upgrade Projects Evaluation and Funding Proposal, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={906E2793-0000-C215-8D5C-BCE2A871DA30}

[259] See more information on EPRI's EVsScale2030 initiative at https://msites.epri.com/evs2scale2030

[260] See more information on EPRI's EVsScale2030 initiative at https://msites.epri.com/evs2scale2030

[261] MA DOER, 2023, Technical Standards Review Group (TSRG) - ESMP Technical Deep Dive Discussion, available at https://www.mass.gov/doc/december-7-2023-esmp-meeting-40-minutes/download

[262] NY Joint Utilities, 2023, Docket 23-E-0070, Joint Utilities' Comments on The Public Service Commission's Order Instituting Proceeding and Soliciting Comments, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={20FE8C88-0000-CF1D-B046-563200EBE36C}

average time needed to complete grid upgrades for SCE. Eversource,[263] National Grid,[264] and Unitil[265] consider the role of bridge-to-wire solutions to defer upgrade needs and provide the utility additional time to deploy infrastructure. Regulators can leverage existing experience and capabilities developed to integrate NWA in distribution system planning when considering the role of NWAs (LBNL, 2025). Similarly, flexible interconnection agreements may enable new loads to connect to the distribution system prior to new distribution system upgrades by curtailing customer load to meet distribution system existing capacity (U.S. Department of Energy, 2024b). Colorado's recent legislation (SB 24-218) required utilities to propose an optional flexible interconnection tariff as an alternative to a system upgrade.[266]

**Table 4-8. SCE's average time to complete distribution system upgrades**

| Project Category | Months to complete |
|---|---|
| Distribution Circuit Upgrade (DCU) | 18 – 24 |
| Distribution New Circuit | 24 – 36 |
| Distribution Substation Upgrade | 48 – 60 |
| Subtransmission Substation Upgrade | 60 – 84 |
| Subtransmission lines Upgrade | 48 – 60 |
| New Distribution Substation | 84 – 120 |
| New Subtransmisison A-Station | 84 – 180 |

Note: Data from A.23-05-010 SCE 2025 GRC Data Request Set NRDC-SCE-003 Prepared by Johnathon Hughes (SCE)

Source: From NRDC[267]

### 4.4.2 Financial risk management options

*Create opportunities for third-party non-utility investors to finance or own proactive assets*

Regulators might consider creating or enabling processes for third parties to finance or own proactive assets needed to meet load growth. Third parties may be better able to tolerate and/or hedge the financial risks of proactive investments. Transferring these risks from ratepayers to the third party may also offer protection for ratepayers from worst-case upward pressure on rates. On the cautionary side, third parties will likely have higher costs of capital than utilities, so this risk transfer may be accompanied by higher asset costs.

263 Eversource, 2024, Electric Sector Modernization Plan: Accelerating a Just Transition to a Reliable and Resilient Clean Energy Future, available at https://www.eversource.com/content/docs/default-source/default-document-library/eversource-esmp%20.pdf

264 National Grid, 2024, Electric Sector Modernization Plan, Future Grid Plan: Empowering Massachusetts by Building a Smarter, Stronger, Cleaner and More Equitable Energy Future, available at https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan.pdf

265 Unitil, 2024, Electric Sector Modernization Plan, available at https://unitil.com/sites/default/files/2024-01/Unitil-ESMP-2025-2050-DPU-FINAL.pdf

266 State of Colorado, 2024, Modernize Energy Distribution Systems: Concerning measures to modernize energy distribution systems, and, in connection therewith, making an appropriation, available at https://leg.colorado.gov/bills/sb24-218

267 NRDC, 2024, Opening Testimony SCE 2025 General Rate Case, available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2305010/7098/526567018.pdf at 13

### *Consider performance incentive mechanisms to reward the right-sizing of the distribution system*

Regulators can develop metrics and set utility performance targets for proactive investments that provide incentives for utilities to right-size system upgrades. These mechanisms can contribute to right-sizing system upgrades by allowing utilities to earn additional revenue for proactive investments that address real needs and result in assets that are utilized. Metrics may consider, for example, infrastructure utilization and energization timeline. Metrics and performance requirements may need to determine the adequate ramp-up period to evaluate utilization for the proactive investment made. Tying earnings to utilization creates an incentive to avoid overbuilding, while tying earnings to energization times discourages underbuilding.

Regulator and utility experience with performance incentive mechanisms, such as those used in utility programs, may offer valuable information when designing incentive mechanisms for other system upgrades. For example, in Colorado, Black Hills Energy received Commission approval for a performance incentive mechanism linked to the program's goal of achieving savings of 2,653 MWh.[268] Black Hills Energy will receive an incentive to achieve over 100% of its annual plan goals.[269] At 101%, the company will earn 1% of the net economic benefits achieved under the plan. For each additional 1%, Black Hills will earn 0.2% of the net economic benefits, up to 150% of the plan goals. This performance mechanism is capped at $30,000/annually.

### *Allow cost recovery in real-time, but allow a rate of return that is dependent on the new asset's utilization*

Regulators could consider allowing utilities to recover asset depreciation costs when assets are built but making capital recovery and rate of return contingent on investments reaching a target utilization rate. A proactive investment to support EV fleet clusters would be allowed to recover depreciation costs as they occur, while the rate of return earnings would only begin once the expected load growth materialized. For example, returns could be tied to a certain target utilization rate. In this case, the regulator, in collaboration with the utility and other stakeholders, would define the standard to determine whether an asset has reached its target utilization rate, as well as the data and reporting requirements necessary to support compliance. This creates an appropriate incentive for utilities to identify lower-risk proactive solutions.

Another benefit of this approach is that it would make cost allocation between current and future electricity customers more equitable. By delaying capital recovery for under-used assets, the regulator alleviates rate pressure on the current rate base, which is not receiving the full benefit of the asset, appropriately shifting that burden to the future rate base at the time that the asset becomes more fully used. A concern is that utilities might underinvest in these assets because they will prefer certain returns to uncertain ones. Regulators could authorize a higher rate of return that reflects the risks

[268] Black Hills Energy, 2022, Docket 22A-0304E, In the Matter of the Verified Application of Black Hills Colorado Electric, LLC For Approval of its 2023-2025 Beneficial Electrification Plan, Direct Testimony and Attachments of Daniel S. Ahrens

[269] CO PUC, 2023, Docket 22A-0304E, In the Matter of the Verified Application of Black Hills Colorado Electric, LLC For Approval of its 2023-2025 Beneficial Electrification Plan.

attendant to these investments to counter this concern, though there may be procedural challenges to doing so.

### *Require economic depreciation for proactive investments instead of accounting depreciation*

Regulators can require utilities to use economic depreciation rather than accounting depreciation to consider the proactive investment assets' expected earning potential. Accounting depreciation—the usual approach—depreciates assets in equal annual installments over their lifetime. Economic depreciation is tied to asset utilization (Europe Economics, 2020).[270] By requiring economic depreciation, regulators can manage the risk of increased customer rates when demand does not materialize. This approach could also better allocate costs between existing and future customers. Under this approach, assets deployed through proactive investments would depreciate less in their initial years after deployment if they are not immediately fully utilized. Earlier in the asset life, while utilization is lower, utilities earn a rate of return on their capital. Later in the asset life, the depreciation level would increase as load growth materializes and asset utilization increases.

### *Categorize proactive investments into risk levels to guide regulatory treatment of costs*

Regulators could classify proactive investments into risk levels and design dedicated regulatory approaches for higher-risk investments. Regulators could authorize a lower rate of return for riskier investments, incentivizing utilities to identify and propose less risky investments. For example, a proactive substation upgrade in a dense urban environment might be considered a lower-risk investment and earn the regular commission-approved rate of return (e.g., the rate of return approved in the most recent rate case), as load growth from electrification may be relatively certain, even if it comes later than initially forecasted. On the other hand, a proactive investment to support a localized large electrification load (e.g., assets to support EV fleet charging) could be seen as carrying greater risk if the customer or customers delay or reduce the extent of their electrification plans. Such an investment might receive a lower return, incentivizing the utility to work towards greater certainty in load expectations, for example, through gaining commitments from customers.

### *Implement upper/lower limits on total return on investment for proactive expenditures*

Regulators may implement upper, lower, or a combination of limits depending on their approach to risk management. An upper limit would place a cap on the total returns a company can earn from a proactive investment. In contrast, a lower limit would provide a minimum return to the company for pursuing proactive investments.[271] Applying a lower limit may help ensure the utility has some incentive to pursue proactive investments needed to support load growth and enable related policy goals. An upper limit may help mitigate any potential utility bias to deploy proactive investments in excess of actual needs and provide protection against large rate increases.

[270] See Europe Economics (2020: p. 43) for additional discussion of this option, including advantages and disadvantages, and a case study of its implementation in the United Kingdom, EE, 2020, Risk Allocation Mechanisms for highly anticipatory investments,

[271] See Europe Economics (2020: p. 33) for additional description of this option, including impact on risk allocation, circumstances where it may be a suitable option, and a case study of this option in practice in the United Kingdom,

*Share risk with customers through tariffs or other regulatory mechanisms*

Regulators can require customers who drive significant load growth to enroll in dedicated rates that support cost recovery for proactive investments. This approach transfers some of the risk from the utility to the customer if load growth does not materialize (CRA, 2024). This approach can also protect ratepayers from unfair cost allocation by requiring customers anticipating significant load growth to make a financial commitment to the utility, contributing to capacity upgrades. For example, AEP Ohio Power Company recently proposed a tariff that would require large data centers that drive infrastructure investment to pay monthly demand charges of no less than 85% of their projected demand even when their demand is lower, or a percentage of the customer's contracted capacity, whichever is greater.[272] [273]

### 4.4.3 Public policy risk management options

*Create a risk sharing mechanism*

In support of economic development dependent upon electric system expansion the private sector, non-governmental organizations, state or Federal government, or state regulators could develop a financial instrument to share in the financial risk of unanticipated, unrealized growth in the near-term. The financial instrument could create a bridge in the near-term years while end-use development is occurring to ensure that the electric grid investments do not slow development. It could also be designed to be utilized only in the case that utilization of the assets does not reach a defined threshold, functioning as a backstop for the investments.

To reduce the possibility of overbuilding the system, this financial mechanism can be paired with risk mitigation approaches. Eligibility for the financial instrument could be dependent on following certain best practice requirements for load planning and project selection. The risk mitigation requirements could include development of a baseline to understand specific load growth-driven investment needs, as well as appropriate consideration and implementation of NWA, DER, grid enhancing technologies, or other energy efficiency measures.

## 4.5 Strategies for minimizing potential negative impacts of proactive investments

Implementing risk management approaches, such as the ones described above, can contribute to minimizing proactive investment risks but may not be able to mitigate negative outcomes entirely. For instance, despite best efforts to manage risk, utilities may pursue proactive investments that result in

[272] AEP Ohio, 2024, Docket 24-508-EL-ATA, In the Matter of the Application of Ohio Power Company for New Tariffs Related To Data Centers and Mobile Data Centers, available at https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A24J23B55758I01206

[273] For contracted capacity between 25,001 and 75,00 kW, customers pay a minimum demand charge for 15,000 kW and 85% of the amount over 25,000. For contracted capacity above 75,00 kW, customers pay a minimum demand charge for 57,500 kW and 100% of the amount over 75,000, not to exceed 85% of the total contracted capacity. AEP Ohio, 2024, Docket 24-508-EL-ATA, In the Matter of the Application of Ohio Power Company for New Tariffs Related To Data Centers and Mobile Data Centers, available at https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A24J23B55758I01206 at 6-7

underutilized assets. In this case, regulators and utilities can consider the following strategies to implement before or after assets are deployed. Strategies implemented before assets are deployed can ensure assets are deployed to target the most suitable locations for proactive investments. Strategies implemented after assets are deployed can incentivize load growth in locations of the system with excess capacity, thereby making more productive use of these assets and potentially avoiding additional costly distribution system investments in other locations.

### 4.5.1 Strategies to minimize negative impacts before deploying proactive investments

*Prioritize areas with greater load growth confidence*

Utilities can prioritize distribution system locations with greater load growth confidence. For instance, areas with significant commercial activity may carry lower uncertainty on load growth from the adoption of EVs and HP. Similarly, highway service plazas may offer greater confidence on the prospect of load growth from EVs. Similarly, utilities can prioritize areas by utilizing analytics and granular data (e.g., vehicle flow patterns) that support the need for future investments.

*When upgrades are necessary, upgrade beyond immediate demand to avoid sequential upgrades*

Utilities can expand upgrade projects to accommodate greater capacity than is currently expected. This can allow utilities to avoid the need to revisit the same asset for incremental upgrades in the future, avoiding the need for sequential upgrades (See Section 4.3). Sequential investments can be more costly since they often duplicate efforts, such as the time, budget, and staff necessary for planning, designing, and constructing distribution system assets. When considering appropriate expansion, utilities may wish to consider likely future load growth using probabilistic methods, to ensure that expansion decisions are tied to reasonable growth expectations.

### 4.5.2 Strategies to minimize negative impacts after deploying proactive investments

*Promote load growth-ready zones*

Utilities should consider promoting locations with lightly utilized distribution system assets to incentivize asset utilization. Utilities could direct marketing, education, and outreach efforts at residential and commercial customers to inform them of options available to increase their load by adopting new EV and heat pump technologies. Utilities could also inform customers of the benefits of load-growth-ready zones, such as expedited energization and reduced or no system upgrade cost. For example, in Section 4.3 we reviewed a New York proceeding where utilities proposed identification and promotion of "areas of capacity" for EV and MHDEV.[274] These are areas where the distribution system can meet near-term EV and MHDEV charging needs without requiring significant upgrades. As part of this strategy, utilities may provide customers with information on existing utility programs supporting technology adoption or other programs available at the state level. Utilities can also design programs to target locations with underutilized assets and channel utility incentives, such as rebates for EV chargers,

[274] National Grid, 2023, Docket 23-E-007, National Grid Supplemental Comments, available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C03F9188-0000-CF12-8B91-BB760DB518BF} at 10

heat pumps, and make-ready infrastructure. In some cases, load-growth-ready zones may also be suitable for deploying distributed generation, minimizing interconnection waiting periods.

### *Small business, commercial, and industrial incentive rates*

Utilities could design and seek regulatory approval to provide lower rates to encourage load growth from existing and new businesses in system locations with available capacity. In addition to incentivizing targeted load growth, these rates may also contribute to local economic development by attracting businesses that create jobs and economic activity. Regulators and utilities can collaborate to establish rate structures, determine customer classes eligible to participate, and determine the duration of the rate offering.

# 5. Summary of Key Considerations for Regulators

A new era of load growth is challenging established utility regulatory practices for managing utility costs of electricity distribution system investments. Regulators must adapt their practices to account for increasing customer demand, both from large localized new users such as data centers and from smaller, more distributed but collectively significant electrification load growth from the adoption of EVs and heat pump heating technologies. In this report, we focus on load growth from homes and businesses that adopt electric vehicles and heat pump heating technologies. Through review of legislation and regulatory dockets in a subset of states, we provide insights into emerging utility and regulatory practices to recover and allocate costs of electrification-driven distribution system investments necessary to accommodate these technologies. Our review included practices for managing, recovering, and allocating costs related to behind-the-meter enabling infrastructure investments, close to the meter utility-side investments, and further upstream distribution system investments.

Section 2 of this report reviews practices related to utility recovery and allocation of electrification program-related costs. Section 3 reviews evolving utility line extension policies that divide responsibility for utility service upgrades between utilities and their customers. Section 4 considers larger investments further upstream in the distribution system, and the central challenge of making investments in advance of load to accommodate uncertain future demand while maintaining sufficient cost control.

This report describes evolving utility practice and considerations for regulators. Here we summarize key considerations by section, followed by some overall conclusions.

## 5.1 Key considerations for programmatic cost recovery

Utility programs support customer adoption of electric vehicles and heat pump technologies, which are not the focus of this report. However, many of these programs also support some electricity delivery infrastructure. Depending on program design, this may include utility-side infrastructure, such as service lines and transformers, and customer-side infrastructure, such as wiring, conduits, electric vehicle chargers, or electrical panel upgrades. Utilities generally recover the costs of these programs from their rate base. Cost recovery and allocation decisions regulators face include:

- Whether to capitalize or expense electrification program costs. Capitalization provides a rate of return, creating a utility incentive for investment, and typically spreads costs over a longer time period (e.g., the expected lifetime of the asset being capitalized), reducing up-front rate impacts. Expensing lowers the total increase in the rate base because the utility does not earn a rate of return, but increases short-term impacts on ratepayers, as expensing often happens on a shorter timeframe equal to the program's duration (e.g., three to four years).

- The time frame over which costs are capitalized, if applicable. In many cases, this time period will coincide with the expected useful life of the asset; however, there may be reasons to choose other periods based on policy goals or desired timing of rate impacts.
- Whether to recover program costs through base rates, or to establish a rider (or other alternative cost recovery mechanism). Relative to base rates, riders generally offer faster cost recovery and greater flexibility. Handling cost recovery through rate cases may offer greater cost certainty and may accommodate greater regulatory oversight of costs.
- Whether to use an existing cost allocation method, such as those established in the most recent rate case, or to establish a new method for electrification program costs. Existing methods have the advantage of prior regulatory vetting, while new methods may offer the opportunity to better match the costs of these investments with their beneficiaries.
- Whether to introduce specific guidance regarding the reasonableness of proposed utility electrification-related investments. Such guidance can provide greater clarity for utilities developing investment strategies and submitting program or investment proposals.

## 5.2 Key considerations for line extension policies

A number of regulated utilities have expanded their line extension allowances for service upgrades required to support electrification. Such expanded allowances support customer adoption of electric vehicle and heat pump technologies by recovering a greater portion of electric service costs from the rate base.

In some cases, legislation or executive orders have required commissions to revise line extension policies for electrification. In other cases, commissions have done so through regulatory actions where line extension policy revisions support public policy goals.

Regulators may wish to consider the benefits of expanding the utility's capacity to serve future customers when setting line extension allowances for electrification. For example, a transformer upgrade on a residential feeder could support future load demand from other customers served by that same transformer. Some utilities adopt line extension policies that allow a customer to be refunded in the case of future demand increased by users of the same infrastructure, which may achieve appropriate cost allocation. Moreover, in some cases, the increased utility sales from a customer's adoption of electric technologies may more than offset the costs of an expanded allowance, lowering utility rates, which aligns with the central rationale for utility allowances.

Line extension allowance expansions may weaken customers' motivations for cost containment, so regulators who expand allowances may wish to be mindful of establishing appropriate mechanisms to ensure that line extensions are conducted in a cost-effective manner. Section 3 offers some examples of existing practices.

## 5.3 Key considerations for proactive investments

Utilities expect significant future growth in demand, though the scale and timing of that demand growth is uncertain. Moreover, current demand is outstripping distribution system capacity in some cases, slowing customer adoption of electric technologies. Given these challenges, some states are launching efforts to establish processes that will support utilities to invest in distribution system assets ahead of load arrival.

Some of the more common features of these emerging proactive investment frameworks that other states may wish to consider include:

- Processes for utilities to identify investments in advance of load for commission approval
- Criteria for evaluation and approval of proposed investments, or processes to establish such criteria
- Requirements for utilities to gather and share relevant data, such as vehicle location and trip data and hosting capacity data
- Target timelines for energization of EV charging infrastructure
- Cost recovery and cost allocation processes for proactive investment costs (see next paragraph)
- Criteria for determining the reasonableness of incurred utility costs for cost recovery purposes

We observed variation in commission and utility preferences for dedicated cost recovery mechanisms versus base rate cost recovery. For instance, in California and Colorado, the legislature allowed utilities to access a dedicated cost recovery mechanism to allow utilities to track costs and adjust rates ahead of their next rate case. In Massachusetts, the Commission determined that a dedicated cost recovery mechanism would be the most appropriate pathway for utilities to pursue proactive investments to mitigate any potential delays that could occur if costs were recovered through distribution rates. In New York, the Commission has required utilities to evaluate options to recover costs outside of rate case proceedings. Conversely, in SCE's ongoing rate case, the utility requested that the capital expenditures needed to proactively support electrification load growth be included in the company's base rates determined in the ongoing proceeding. Similarly, in North Carolina, Duke Energy received Commission approval to recover proactive investments to enable EV load growth through base rates.

Dedicated cost recovery mechanisms established outside of rate cases may provide faster cost recovery than waiting for a future rate case proceeding. They may also contribute to ensuring investments classified as proactive are adequately evaluated. Alternatively, recovering costs for proactive investments through distribution rates may ensure that proactive investments are considered as part of the overall utility investment needs and prioritized accordingly. It is likely that no one approach will prove best for all states.

Given the inherent uncertainty in investing ahead of load, managing risk—to utility ratepayers, utility shareholders, and customers adopting technologies—is a central task for regulators to grapple with when facilitating proactive investment. Proactive investments must manage stranded asset risks; risks of making suboptimal investments given uncertainty about future load growth; and risks that cost allocation decisions made at time of investment will not match the eventual beneficiaries of the future investment. Traditional just-in-time investments also involve risks. Waiting for load certainty may create long energization timelines, hampering customer adoption of preferred technologies and threatening policy goals that depend on that adoption. Insufficient distribution system capacity may lock in long-lived incumbent technologies. Utilities will not receive new revenues as quickly, and investments made under time pressure to serve immediate demand may not adequately consider future grid needs.

To manage these risks, regulators can consider:

- Establishing processes that ensure adequate data availability and analysis
- Requiring load forecasting methods that extend time horizons and explicitly consider the uncertainties surrounding the timing of electrification technology adoption
- Requiring third party review of forecasts, analyses, and proposed investments to promote transparency and increase confidence that decisions are made objectively
- Require consideration of NWAs and bridge-to-wires solutions as a strategy for maintaining options in uncertain investment scenarios

Regulators can also consider financial incentives for utilities to make appropriate proactive investments. Approaches could include:

- Incentives that reward utilities for right-sizing distribution systems
- Rate of return or asset depreciation structures that make utility earnings dependent on deployed assets being utilized
- Varying the allowable rate of return depending on the level of risk of the investment
- Setting caps on utility earnings for proactive investment to manage impacts on rates; and
- Sharing risk with customers (such as through dedicated tariffs) or allowing more risk-tolerant third parties to take on risks of proactive investment

## 5.4 Key considerations for enabling complementarities and ensuring coordination

Load growth will require investments across the distribution system, from core upstream assets that serve large groups of customers to assets near and behind-the-meter that enable individual customer load growth. In this report, we addressed investments as discrete elements (i.e., utility programs, line extensions, and proactive upstream investments) to provide detailed insights into existing practices. Regulators may benefit from considering potential complementarities and opportunities for coordination across these mechanisms. This can avoid decision-making silos and support the deployment of cost-effective solutions. For instance, utility electrification programs may be an effective way to pilot line extension policy changes to gather insights and inform longer-term actions. Similarly, utility program design may consider opportunities to include TOU rates, load management measures, or support for demand flexibility technologies, which may reduce, defer, or mitigate the need for an electric service upgrade. Such measures might reducing the need for line extension policy reforms, or the frequency in which upgrades are necessary, and consequently their potential impact on the rate base. Regulators can also consider coordinating with existing planning efforts, such as integrated distribution system planning, to ensure proactive investment needs are considered alongside other distribution system needs and prioritized accordingly.

In some cases, regulators may face similar decisions in separate domains of electrification-related cost recovery. For example, both programmatic and proactive investments must be assessed for reasonableness, allocated among customer segments, and recovered from the rate base. Regulators can consider harmonizing their processes and requirements for these expenses to the extent that it makes sense to do so.

In terms of regulatory treatment of proactive distribution system investments specifically, it is important to recognize that regulatory practice is in its early stages. State regulators will do well to coordinate and share lessons learned as they pilot new approaches. With billions of dollars of distribution system investment at stake, continued learning and information-sharing will pay dividends over time.

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# APPENDIX A. Utility electrification programs details

**Table A-1. Behind-the-meter infrastructure ownership**

| Who owns behind-the-meter infrastructure? | Utility (State) |
|---|---|
| ***Utility*** | Xcel Energy, DCFC; Minnesota Power (MN); Duquesne, DCFC (PA). |
| ***Customer*** | Black Hills Energy (CO); Ameren, ComEd (IL); National Grid, Eversource, and Unitil (MA), DTE, Consumers, I&M (MI); Minnesota Power (MN); Rhode Island Energy (RI); BG&E, Pepco, Delmarva (MD); Pacific Power (OR); DEC, DEP (NC); Duquesne (PA). |
| ***Utility or customer*** | PG&E, SCE, SDG&E (CA); Xcel Energy (CO); Xcel Energy, Residential (MN); Entergy (AR), DEC, DEP (NC). |
| ***Third-party*** | MI (DTE) |

**Table A-2. Utility expensing and capitalization of behind-the-meter costs**

| How are behind-the-meter electrification program costs accounted? | Utility (State) |
|---|---|
| **Capitalization of behind-the-meter costs** | SCE, PG&E (CA); Xcel Energy, Black Hills Energy (CO); DTE, Consumers, I&M (MI); Xcel Energy (MN), Rhode Island Energy (RI) |
| **Expensing of behind-the-meter costs** | ComEd (IL); National Grid, Eversource, Until (MA) |

**Table A-3. Utility program rate structures and load management**

| Does the utility program require customers to participate in specific rates or load management measures? | Utility (State) |
|---|---|
| **Load management** | National Grid, Eversource (MA); ComEd* (IL); PGE (OR); Pepco, Delmarva (MD) |
| **Rate and load management measures** | PG&E, SCE, SDG&E (CA); Xcel Energy (CO), DTE (MI) |
| **Rate (i.e., price control)** | Black Hills Energy (CO); ComEd* (IL); Until (MA), Consumers, I&M (MI), Xcel Energy, Minnesota Power, Otter Tail Power (MN); Pacific Power (OR) |
| *Must participate in grid integration measure OR enroll in a specific rate. | |

**Table A-4. General and electrification-specific reasonableness standards**

| State | General reasonableness standard<br>*General reasonableness standard applied by the regulators* | Electrification reasonableness standards<br>*Reasonableness standard for electrification-related decisions* |
|---|---|---|
| **AR** | The Arkansas Public Utilities Code established a regulatory framework *"to provide just and reasonable rates to consumers in this state and enables public utilities in this state to provide reliable service while maintaining stable rates."*[275] | n.a. |
| **CA** | The California Public Utilities Code established that all rates must be just and reasonable. Additionally, it also requires utilities to *"ensure adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities to promote safety, health, comfort, and convenience."*[276] | For transportation electrification investments, the California Public Utilities Code established that utility programs proposed must aim to minimize costs and maximize benefits. It also required the Commission to approve or modify and approve, programs that do not compete with non-utility businesses unfairly, include performance accountability measures, and are in the interests of ratepayers.[277]<br><br>Additionally, the Commission previously approved *per se* reasonableness metrics for SCE and SDG&E, which, if achieved by the utility, would result in its authorized spending being considered reasonable.<br>The metrics include specific targets for infrastructure deployment, including ownership, customer classes, equity considerations, building types, and budget caps in aggregate and per port. See Section 2.4 for more details on these metrics. |
| **CO** | The Colorado Revised Statutes established that utility rates must be just and reasonable and require | For transportation electrification, the legislature, through SB19-077 established the requirement for utilities to submit |

[275] State of Arkansas, 2020 Arkansas Code, Title 23 - Public Utilities and Regulated Industries, Subtitle 1 - Public Utilities and Carriers, Chapter 4 - Regulation of Rates and Charges Generally, Subchapter 12 - Formula Rate Review Act, § 23-4-1202. Findings and intent, available at https://law.justia.com/codes/arkansas/2020/title-23/subtitle-1/chapter-4/subchapter-12/section-23-4-1202/

[276] State of California, Public Utilities Code, Article 1, Chapter 764, available at https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=1.&title=&part=1.&chapter=3.&article=1.

[277] State of California, Public Utilities Code, Article 2, Chapter 764, available at https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=1.&title=&part=1.&chapter=4.&article=2.

| State | General reasonableness standard *General reasonableness standard applied by the regulators* | Electrification reasonableness standards *Reasonableness standard for electrification-related decisions* |
|---|---|---|
| | utilities to *"ensure adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities to promote safety, health, comfort, and convenience."*[278] | Transportation Electrification Plans, requiring that *"the retail rate impact from the development of electric vehicle infrastructure must not exceed one-half of one percent of the total annual revenue requirements of the utility."* Additionally, the law provided the Commission with a range of items that proposed utility plans are reasonably expected to meet, including, for example, improving the use of the electric grid, increasing transportation electrification, and contributing to improved air quality.[279]<br><br>For beneficial electrification, the legislature, through SB 21-246, established the requirement for utilities to submit beneficial electrification plans and for the Commission to *"allow an investor-owned electric utility to implement cost-effective beneficial electrification plans that support voluntary customer adoption of beneficial electrification measures."* The law also describes what the plans must include, such as proposals for programs to advance beneficial electrification, programs targeting low-income households, budgets, targeted number of installations, and projected cost-effectiveness.[280] |
| **IL** | The Illinois Compiled Statutes require | For beneficial electrification, the legislature, |

[278] State of Colorado, Colorado Revised Statutes, Article 3, Title 40, available at https://advance.lexis.com/documentpage/?pdmfid=1000516&crid=cc891430-2894-4b20-bf2f-e17d056d5651&config=014FJAAyNGJkY2Y4Zi1mNjgyLTRkN2YtYmE4OS03NTYzNzYzOTg0OGEKAFBvZENhdGFsb2d592qv2Kywlf8caKqYROP5&pddocfullpath=%2fshared%2fdocument%2fstatutes-legislation%2furn%3acontentItem%3a61P5-X011-DYDC-J0FX-00008-00&pdcontentcomponentid=234176&pdteaserkey=sr0&pditab=allpods&ecomp=6s65kkk&earg=sr0&prid=236c0a9c-0100-457f-92b8-30113f40e8fc

[279] State of Colorado, 2019, SB 19-077 Transportation Electrification Plans, available at https://leg.colorado.gov/sites/default/files/documents/2019A/bills/2019a_077_enr.pdf

[280] State of Colorado, 2021, SB 21-246, Concerning Measures to Encourage Beneficial Electrification, and, in Connection Therewith, Directing the Public Utilities Commission and Colorado Utilities to Promote Compliance With Current Environmental And Labor Standards And Making An Appropriation, available at https://leg.colorado.gov/bills/sb21-246

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| | the Commission to *"[…] establish the rates or other charges, classifications, contracts, practices, rules or regulations proposed, in whole or in part, or others in lieu thereof, which it shall find to be just and reasonable."*[281] | through the Climate and Equitable Jobs Act, Public Act 102-0662, introducing the requirement for utilities to file beneficial electrification plans, established that *"The plan shall be determined to be cost-beneficial if the total cost of beneficial electrification expenditures is less than the net present value of increased electricity costs (defined as marginal avoided energy, avoided capacity, and avoided transmission and distribution system costs) avoided by programs under the plan, the net present value of reductions in other customer energy costs, net revenue from all electric charging in the service territory, and the societal value of reduced carbon emissions and surface-level pollutants, particularly in environmental justice communities. The calculation of costs and benefits should be based on net impacts, including the impact on customer rates."* The law provides the Commission with a range of requirements utility plans are expected to reasonably address, including, for example, maximizing total energy savings and rate reductions, addressing environmental justice, and contributing to reducing carbon emissions.[282] |
| **MA** | The Massachusetts General Laws require the Commission to apply the just and reasonable standard for utility rates.[283] [284] | For transportation electrification, the Commission may approve utility cost recovery for distribution company proposals to own and operate EV charging infrastructure. To receive Commission approval, a utility proposal must *"[…] be in the public interest; meet a need* |

281 State of Illinois, Illinois Compiled Statutes, Ch. 111 2/3, par. 9-201, available at https://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=022000050K9-201

282 State of Illinois, 2021, Climate and Equitable Jobs Act, available at https://epa.illinois.gov/content/dam/soi/en/web/epa/topics/ceja/documents/102-0662.pdf

283 State of Massachusetts, General Laws, Part I, Title XXII, Chapter 164, available at https://malegislature.gov/Laws/GeneralLaws/PartI/TitleXXII/Chapter164/Section94#:~:text=Unless%20the%20department%20otherwise%20authorizes,authorize%20rates%20filed%20by%20an

284 Attorney Gen. v. Dep't of Pub. Utilities, 98 Mass. App. Ct. 1117, 157 N.E.3d 112 (Mass. App. Ct. 2020), available at

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| | | *regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market; and not hinder the development of the competitive EV charging market."*[285] |
| **MD** | The Maryland Statutes give the Commission the authority to set just and reasonable rates.[286] | n.a. |
| **MI** | The Michigan Public Utility Laws require the Commission to ensure that utility rates are just and reasonable.[287] | n.a. |
| **MN** | The Minnesota Statutes require *"The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the* | For transportation electrification, the Commission requires EV related utility proposals to include a cost-benefit analysis for significant investments. For pilots, the Commission requires proposals to include evaluation metrics and expected learning outcomes.[289] |

[285] MA DPU, 2014, Docket D.P.U. 13-182-A, Order on Department Jurisdiction Over Electric Vehicles, the Role Of Distribution Companies in Electric Vehicle Charging and Other Matters, available at https://casetext.com/case/attorney-gen-v-dept-of-pub-utilities https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9233599

[286] State of Maryland, 2023 Maryland Statutes, Public Utilities, Division I - Public Services and Utilities, Title 4 - Rate Regulation, Subtitle 1 - General Provisions, Section 4-102 - Commission Power to Regulate Rates, available at https://law.justia.com/codes/maryland/public-utilities/division-i/title-4/subtitle-1/section-4-102/

[287] State of Michigan, Michigan Public Service Commission, Act 3 of 1939, available at https://www.legislature.mi.gov/documents/mcl/pdf/mcl-Act-3-of-1939.pdf

[289] MN PUC, 2017, Docket 17-879 In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Order Making Findings and Requiring Filings

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| | *investment in such property."*[288] | |
| **NC** | The North Carolina Statutes require the Commission to set just and reasonable rates.[290] | The North Carolina Statutes establish that the Commission, when reviewing a utility performance-based regulation application, may consider if it *"Encourages beneficial electrification, including electric vehicles."*[291] |
| **OR** | The Oregon Revised Statues give the Commission the authority to *"protect such customers, and the public generally, from unjust and unreasonable exactions and practices and to obtain for them adequate service at fair and reasonable rates. The commission shall balance the interests of the utility investor and the consumer in establishing fair and reasonable rates. Rates are fair and reasonable for the purposes of this subsection if the rates provide adequate revenue both for operating expenses of the public utility or telecommunications utility and for capital costs of the utility, with a return to the equity holder".*[292] | For transportation electrification, the Oregon Revised Statutes establish the factors to be considered when determining if a utility proposal to support transportation electrification. These include contributing to greenhouse gas emissions reductions over time, and benefits to utility customers, such as downward pressure on rates and greater access to EV charging infrastructure.[293] |
| **RI** | The Rhode Island General Laws established that the policy of the state aims to regulate utilities fairly and provide just and reasonable rates.[294] | n.a. |
| **PA** | The Pennsylvania Consolidated | n.a. |

288 State of Minnesota, Minnesota Statutes, 216B.16 Rate Change; Procedure; Hearing., Subd. 6., available at https://www.revisor.mn.gov/statutes/cite/216B.16#:~:text=The%20commission%2C%20in%20the%20exercise,to%20meet%20the%20cost%20of

290 State of North Carolina, North Carolina Statutes, Chapter 62, Public Utilities, Article 7, Rates of Public Utilities, available at https://www.ncleg.net/enactedlegislation/statutes/html/bychapter/chapter_62.html

291 State of North Carolina, North Carolina Statutes, Chapter 62, Public Utilities, Article 7, Rates of Public Utilities, available at https://www.ncleg.net/enactedlegislation/statutes/html/bychapter/chapter_62.html

292 State of Oregon, Oregon Revised Statutes, Vol. 19, Title 57, Chap. 756. Pub. Utility Commission, § 756.040, available at https://oregon.public.law/statutes/ors_756.040#:~:text=The%20commission%20may%20participate%20in,service%20to%20or%20within%20this

293 State of Oregon, Oregon Revised Statutes, Vol. 19, Title 57, Chap. 757. Util. Regul. Generally, § 757.357, available at https://oregon.public.law/statutes/ors_757.357

294 State of Rhode Island, Rhode Island General Laws, Title 39, Public Utilities and Carriers, Chapter 1, Public Utilities Commission, R.I. Gen. Laws § 39-1-1, available at https://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-1.HTM

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| | Statutes require utility rates to be just and reasonable.[295] | |
| **WA** | The Revised Code of Washington requires utilities to set just and reasonable rates.[296] | For transportation electrification, the Revised Code of Washington establishes that the commission may allow utilities to earn an incentive rate of return on electric vehicle charging infrastructure as long as the investments *"[…] do not increase the annual retail revenue requirement of the utility, after accounting for the benefits of transportation electrification in each year of the plan, in excess of one-quarter of one percent."*[297] |

[295] State of Pennsylvania, Consolidates Statutes, Title 66, Chapter 13, Sec. 301, Rates and Distribution Systems, available at https://www.legis.state.pa.us/CFDOCS/LEGIS/LI/consCheck.cfm?txtType=HTM&ttl=66&div=00.&chpt=013.
[296] State of Washington, Revised Code of Washington, Title 80, Chapter 80.04, Section 80.04.130, available at https://app.leg.wa.gov/RCW/default.aspx?cite=80.04.130
[297] State of Washington, Revised Code of Washington, Title 80, Chapter 80.28, Section 80.28.360, available at https://app.leg.wa.gov/RCW/default.aspx?cite=80.28.360